DYING INTESTATE OR WITH A WILL ON TOXIC ESTATE?

AN EVALUATION OF PETROLEUM FISCAL SYSTEMS AND THE ECONOMIC AND POLICY IMPLICATIONS FOR DECOMMISSIONING OF ONSHORE CRUDE OIL FIELDS IN NIGERIA

By

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Abstract

Many giant fields in the world like the onshore fields in Nigeria which were initially discovered over half a century ago, have begun to see consistent decline in production and profit, and are gradually entering into the economic end of field life or decommissioning phase. Characteristically, in most regions with mature fields, the large multinational oil companies have begun to sell their oil fields to small indigenous companies who may not be financially robust enough to complete the decommissioning, when it occurs. Because of the pervasive societal impact of the oil industry, if an investor fails to properly decommissioning the infrastructure, a responsible government will have to pay for the proper decommissioning, else society will suffer the socioeconomic, political, health and environmental impact. Therefore, society needs to be effectively engaged in the development of a sustainable decommissioning policy framework, which is hindered if society is uninformed and lacks access to pertinent information.

Currently, there is abysmal information in the public space on the cost of decommissioning liabilities of oil fields, especially in developing countries like Nigeria. The public also need simple interpretative ways to determine the vulnerability of a county or entity to decommissioning default risk and the imminence of a default risk. Furthermore, there is currently, no way to benchmark the level of maturity or level of preparedness for decommissioning phase such that countries and entities can identify their gaps to a sustainable decommissioning policy framework and define a roadmap to close the gaps. These are important challenges to vigorous public participation, which is an essential requirement for development and implementation of any sustainable public policy for a public issue like decommissioning of crude oil fields.

This study adopted several research methods to develop and introduce a new cost estimating methodology that uses publicly declared cost of asset retirement obligations (ARO) to determine a plausible cost estimate range for decommissioning liabilities. It was demonstrated with Nigeria onshore crude oil fields, which it determined to have a rough order of magnitude cost estimate for decommissioning liabilities that could be as high as $3 billion. Secondly, it also introduced decommissioning coverage ratio (DCR) and decommissioning coverage ratio vector (DCRV) as new metrics to evaluate the vulnerability to and imminence of decommissioning default risk. In demonstrating these new metrics, this study determined that the imminence of and vulnerability to decommissioning default risk for the onshore crude oil fields in Nigeria, with respect to any of the available revenue streams, is high. Thirdly, it developed a graded scale maturity model for sustainable decommissioning of petroleum fields. The model described as Fairbanks maturity model for sustainable decommissioning in the petroleum industry, has five progressive levels of maturity. It leveraged the methodology used for similar maturity models developed in other industries and for business management, and a comparative analysis of level of progress in decommissioning frameworks between some countries with leading decommissioning experience in the petroleum industry, to develop the Fairbanks maturity model. Based on the Fairbanks maturity model, frameworks for sustainable decommissioning of Nigeria onshore crude oil fields were evaluated to be at Level 1, Ad hoc maturity level, which is the lowest maturity level. Recommendations to close the identified gaps were also were made. These methodologies can be applied to any petroleum producing region or entity in the world and are advancements to the frontier of knowledge in the management of decommissioning phase for petroleum fields in general and Nigeria onshore fields in particular.

Table of Contents

Page

List of Figures

List of Tables

Page

Acronyms and Abbreviations (i)

Acronym/Abbreviations	Meaning
AACE	American Association of Cost Engineers; Association for the Advancement of Cost Engineering
ACostE	UK Association of Cost Engineers
ADNR	Alaska Department of Natural Resources
ADR	Asset Decommissioning Ratio
AER	Alberta Energy Regulatory Agency
ANSI	American National Standard Institute
ARO	Asset Retirement Obligation
BCOGC	British Columbia Oil and Gas Commission
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
CDR	Corporate Decommissioning Ration
CIT	Corporate Income Tax
CPDF	Cumulative Probability Density Function
DCA	Decline Curve Analysis
DCR	Decommissioning Coverage Ratio
DCRV	Decommissioning Coverage Ratio Vector
DD&R	Decommissioning, Dismantlement & Restoration
DECC	Department for Energy and Climate Change
DPR	Directorate of Petroleum Resources
DR&R	Decommissioning, Remediation & Restoration
E&P	Exploration & Production
EIA	Environmental Impact Assessment
EOFL	End of Field Life
EPA	Environmental Protection Agency
ESA	Environmental Site Assessment
FMENV	Federal Ministry of Environment

Acronyms and Abbreviations (ii)

Acronym/Abbreviations	Meaning
GDP	Gross Domestic Product
GOM	Gulf of Mexico
GT	Government Take
IEA	International Energy Agency
IMO	International Maritime Organization
IOC	International Oil Companies
JV	Joint Venture
LLR	Licensee Liability Rating
LMR	Liability Management Ratio
LNG	Liquefied Natural Gas
LOC	Local Oil Company
MFC	Marginal Field Company
MMbopd; Mbopd	Million barrels of oil per day; Thousand barrels of oil per day
MMbbls/d; Mbbls/d	Million barrels of oil per day; Thousand barrels of oil per day
MPTA	Million tons per annum of Liquefied Natural Gas
NAPIMS	National Petroleum Investment and Management Services
NNPC	Nigeria National Petroleum Corporation
NOC	National Oil Company
NPDC	Nigeria Petroleum Development Company
OCS	Offshore Continental Shelf
OECD	Organization for Economic Co-operation and Development
OGA	Oil and Gas Association, UK
OML	Oil Mining Lease
OOIP	Original Oil in Place

Acronyms and Abbreviations (iii)

Acronym/Abbreviations	Meaning
OPEC	Organization of Petroleum Exporting Countries
PPRS	Petroleum Production Reporting System
PPT	Petroleum Profit Tax
PSC	Production Sharing Contract
R/P; RtP	Reserve to Production
ROM	Rough Order of Magnitude
RRR	Reserve Replacement Ration
SC	Service Contract
SPE	Society of Petroleum Engineers
TBL	Triple Bottom Line
UKCS	United Kingdom Continental Shelf
UNCLOS	United Nations Convention on the Law of the Sea
UNEP	United Nations Environmental Programme
WBS	Work Breakdown Structure
YoY	Year-on-Year

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1. Preamble and Overview

1.1. Preamble

The petroleum industry is a very significant part of the worldwide economic system. Petroleum, particularly crude oil, is a major source of energy and fossil fuel that drives development and economic growth globally. However, crude oil is a non-renewable and finite natural resource. Several alternative energy sources have been and are being explored and developed to replace crude oil as an energy source (Heun & de Wit, 2012). Currently, no source has been able to efficiently and effectively replace crude oil. While optimism continues to drive the search and development efforts for a better alternative energy source to crude oil, it remains a concern that crude oil is a finite resource. Human societal, economic, and developmental growth is neither going to be deliberately arrested nor desired to be stagnant owing to its limited quantity. The concern about how long it will continue to be adequately available to sustain economic and developmental growth, is therefore genuine. The apprehension of a world running out of crude oil supply has dominated and monopolized attention away from other problems, such as decommissioning, remediation, and restoration of crude oil development sites, that are associated with the economic end of field life (EOFL) of a crude oil energy system. In addition, this is more evident in Nigeria, where crude oil export is almost the only source of foreign exchange and government income.

As a finite economic natural resource, crude oil reserves in a particular area or boundary definition will at some time become exploited to a level where the remaining exploitable quantity from the reserves will be too small and no longer profitable to operate. It is altruistically expected that the associated crude oil exploitation foot print is either removed or made benign, to the continued human societal and economic growth of the former crude oil producing region or area. While the decision to end the economic operation of a crude oil exploitation venture, that is decommissioning and abandonment, may be compelled by the net economic loss from it operation, the decision to restore the environment back to its post operational condition is discouraged by the lack of pecuniary incentives at the last phase of the crude oil investment life cycle. Production volumes become too low and operational overhead become too high for a significant net profit to be made. At this stage of the investment life cycle, addition of another expense element, such as proper decommissioning and abandonment of crude oil producing facilities, may only be achieved by either an altruistic drive or regulatory compulsion (Islam & Khan, 2013).

Similar to most mature crude oil producing regions globally, Nigeria is beginning to observe significant decline in production from most of its initial crude oil fields, particularly the onshore fields discovered in the 1950s and 1960s. Interestingly and as a matter of reality with exploitation of a finite resource, globally, every oil producing region has some fields either already in this stage or in a situation where it will soon be at this stage in its economic life, such as conventional oil fields in Canada, Alaska, Texas, and Malaysia. As observed by Kaiser & Liu (2014), Kaiser & Pulsipher (2008), and Kemp & Stephen (1998), this same characteristic situation is also expansively evident in the United Kingdom Continental Shelf (UKCS) and Gulf of Mexico (GOM). The UKCS and GOM fields are offshore fields, located in the open sea at a depth of approximately 1000 feet or more, and are in developed nations with mature regulatory policy, socioeconomic and political frameworks (Ayoade, 2002). Comparatively, most of

Nigeria's current mature fields are onshore and Nigeria is a developing nation with less mature regulatory policy, and socioeconomic and political frameworks (Azaino, 2012; Kelani, 2009).

1.2. Case for Study

In extant literature and academic research, there is more focus on decommissioning of offshore oil fields, in comparison to onshore oil fields. Located in international waters and in a water body environment which can be a challenge to control, offshore fields appear to be a more visible risk in the event of a failed decommissioning project. Therefore, understandably, a significant proportion of academic and industry research efforts are focused on the international maritime legal and environmental pollution frameworks associated with decommissioning of offshore platforms (Gorman & Neilson, 2012). A significant number of decommissioning activities, including a stellar failed decommissioning attempt (the Brent Spar) that had attendant huge negative consequences, have been experienced in offshore fields. Comparatively, onshore fields have limited experience with high profile decommissioning projects. Moreover, most of these offshore decommissioning projects took place in the GOM and UKCS. As a result, most of the existing studies are based on the sociopolitical and economic environment of the United States of America (the United States) and United Kingdom (the UK). The few studies extended to developing nations, such as Nigeria, are only focused on the maritime legal frameworks (Ayoade, 2002; Mato, 2012).

Onshore fields in Nigeria have been in production for over 50 years and associated characteristics of mature fields are beginning to emerge. For example, major international oil companies (IOCs) or multinational oil companies (MOCs), have started to divest their onshore assets to small indigenous companies. Currently, the overall production from Nigeria is holding flat at approximately 2,500 Mbopd (British Petroleum, 2016). The decline in crude oil production from onshore fields is not apparent to the public due to the obliterating effect of increase in crude oil production from offshore fields. Consequently, there is less concern and absence of conscious efforts toward a sustainable decommissioning policy framework for the onshore fields in Nigeria – a situation that raises some important questions. Is decommissioning of the onshore fields an imminent problem to worry about in Nigeria at this time? Is the petroleum fiscal and regulatory system adequately prepared to handle decommissioning of onshore crude oil fields?

A sustainable approach will attempt to assess the risk associated with decommissioning of Nigeria's onshore fields, identify the credible scenarios and time line, and seek for an optimal technical and socioeconomic mitigation strategy. Less developed countries, such as Nigeria and corporate bodies that are slow or reluctant to expend financial resources on decommissioning, will prefer to adopt a simple and easy method to know how much and how imminent is their exposure to decommissioning obligations. This will help them to better acknowledge the urgency to develop and ensure that their risk response plan or strategy is appropriate. This study is focused on the problem of sustainable decommissioning of onshore crude oil fields and how it could be addressed through the petroleum fiscal and regulatory system, particularly in Nigeria.

1.3. Summary of the Problem

Consistent decline in production and economic returns have already been experienced at several old petroleum fields globally. In comparison to the production phase, where there are some economic prizes to be won, society is not significantly engaged in the management of peculiar risks associated with the decommissioning phase of the petroleum industry that has limited or no economic prize at stake, but instead, liabilities to bear. There should be some comfort in knowing that adequate proactive mitigation measures are in place to protect society from the potential adverse effects that could result from the end of economic life of these fields. However, there are not sufficient proactive measures because society has not been engaged to push the government and industry for these mitigating measures, in comparison to how it has been pushing for transparency with revenues from the petroleum resources, and good environmental stewardship during pre-development and development phases. Society is not engaged because it is not effectively informed and does not have the end of economic life of these fields in the mental horizon. Society is not effectively informed because data related to decommissioning, similar to most activities in the petroleum industry, are propriety and not easily interpretative. Generally, the extractive industry has had problems with low level of stakeholder's awareness that is behind most of the outrages against the industry (Sandman, 1998; 2003a; 2003b; 2012; Sheppard, 2017). There is a dearth of studies on decommissioning of petroleum fields that are favorably biased toward data already available and accessible in the public space.

First, there is no easy way for the public to predictively become aware of the cost of decommissioning liabilities associated with petroleum fields under their purview. The cost of decommissioning liabilities or related data are for the most part held proprietary by the oil companies and in some cases, by the government regulatory agencies. This is the situation in most countries, particularly developing nations such as Nigeria and its onshore crude oil fields that do not have any publicly available rough order of magnitude (ROM) cost estimate for their decommissioning liabilities. This is attributed to lack of publicly available information on decommissioning phase activities in Nigeria. In most nations, society is not adequately aware of the cost and pervasive extent of the scope of decommissioning liabilities from petroleum fields due to huge information asymmetry that disproportionally favors the oil companies.

In addition, there is no amenable way for the public to predictively know that risks from the decommissioning phase of the petroleum fields are about to be released. Again, due to information asymmetry, the public does not easily know how much production, and hence rent revenue, could continue to come from the petroleum fields that could act as collateral against the associated decommissioning liabilities. The existing attempt to develop some metrics for predicting the exposure to these risks have not only focused on companies and individual assets, but continue to be fraught with the problem of proprietary information. Societies, particularly in developing nations such as Nigeria with weak public institutions, do not have publicly amenable ways to predictively know their vulnerability to the risk of oil companies defaulting to meet their decommissioning obligations. Currently and similar to several countries, there are no good indicators or proxies to demonstrate that decommissioning of onshore crude oil fields in Nigeria is becoming an imminent problem. The ratio of the remaining petroleum revenue to the cost of meeting asset retirement obligation (ARO) or decommissioning liability, has been used by several authors (Kaiser & Liu, 2015) as indicative of an entity's level of exposure to risk of default in meeting decommissioning liabilities at GOM, Canada, and UKCS. However, this is a snap shot and one-dimension indicator. Similar to any one-dimensional factor, it does not provide pragmatic and temporal insights to the risk of default by industry operators to meet their decommissioning liabilities or asset retirement obligations. For example, the inter-temporal perspective and timing for release of the risk event cannot be deciphered from a one-dimensional indicator. To start with, Nigeria which is the case study for this research does not have the one-dimension ratio or indicator in academic and public space. From extensive literature review undertaken in this study, no previous research has made an attempt to evaluate this indicator for oil fields in Nigeria.

Furthermore, development efforts toward addressing the challenges of decommissioning are disparate within the industry and amongst regions globally. From extant literature and discussions, there is neither a defined tool nor some form of reference and measurable scale to ascertain gaps with decommissioning policy development in an entity, which is unlike some other disciplines or industries that have organizational process/policy evaluation and maturity tools. A World Bank study identified critical areas recommended for a sustainable decommissioning policy take-off (World Bank, 2010). However, it did not result in a simple, replicable, and comprehensive tool for gap evaluation, particularly for developing countries. Unlike other disciplines with comprehensive and defined development frameworks and roadmaps (de Bruin et al., 2005; Crawford, 2015; Tarallo, 2016; Unger et al., 2015), there is no comprehensive basis for benchmarking, gap analysis, and roadmap toward a higher maturity level of preparedness to attain sustainable decommissioning at the end of the economic life of the petroleum fields. This is more imperative for some developing nations, such as Nigeria, that appear to have not given thoughts to decommissioning of its petroleum fields.

Overall, the issue of decommissioning of petroleum fields has been approached from a disparate perspective, either giving attention to offshore fields to the neglect of onshore fields, or individual regional or functional element perspective to the neglect of an integrated perspective. There is no interdisciplinary and comprehensive approach to address the challenges of the decommissioning phase of the petroleum industry which may linger into future generations. This is a gap in society's effort toward sustainable development of petroleum resources and hindrance to public discussions and participation, which is one of the identified key challenges with the development of a sustainable public policy, such as the petroleum field decommissioning policy (Marzuki., 2015; Sinclair & Diduck, 2016).

1.4. Overview, Contribution to Knowledge, and Potential Benefits

This study explored the fiscal, socioeconomic, and political context surrounding sustainable decommissioning of mature onshore crude oil fields using Nigeria as a case study. Based on the empirical situation and comparative analysis with best practices in decommissioning from other nations, it established a basis for urgency with the development of a sustainable decommissioning framework for onshore fields in Nigeria. This basis for urgency, particularly in terms of a pragmatic and temporal approach and for Nigeria's onshore crude oil fields, has hitherto not been in the knowledge space. It consists of the **corporate (or region as in this case) decommissioning coverage ratio (DCR)**, which is a one dimension snapshot decommissioning liability or risk exposure indicator, and a complementary pragmatic and temporal approach described as the **decommissioning coverage ratio vector (DCRV),** which is developed as one of the outcomes from this study.

Kaiser (2015a) developed a tableau for decommissioning liability or risk coverage ratio, which he described as corporate decommissioning ratio (CDR) and asset decommissioning ratio (ADR) for corporate entities and individual asset in the GOM, respectively. From investigations in this study, apart from the fact that these metrics were defined only for individual companies or assets and not extended to regions, interestingly, these indicators have never been determined for individual assets, companies, or petroleum fields in Nigeria.

Decommissioning coverage ratio is a ratio of the remaining potential revenue to the cost of meeting decommissioning liabilities or ARO at a particular point in time or year. It is a snap shot indicator with inherent deficiencies of a one-dimension indicator. This study develops a new decommissioning risk exposure metric that addresses the deficiencies of a snapshot and one-dimension indicator in the evaluation of decommissioning risk exposure in Nigeria onshore fields in particular, and the petroleum/non-renewable natural resource sector in general. The new metric, described as **DCRV,** utilizes a timeline-based approach. Complementing the decommissioning coverage ratio, it demonstrates an entity's level of exposure to imminent risk of default in meeting decommissioning liabilities. DCRV requires the generation of credible profile forecast for the remaining crude oil production volumes, associated revenue streams, and layout of the revenue over a temporal scale. Basically, it is a retroactive or backward collation of the cumulative remaining revenue streams to cover the estimated decommissioning cost. It yields a better timing perspective, and hence an inference as to the urgency and argument for a decommissioning strategy and policy development in a region. The metric DCRV was demonstrated with the case study, where it showed a need to urgently develop a decommissioning strategy and policy for Nigerian onshore crude oil fields. This algorithm for determination of exposure to decommissioning default risk (i.e., Production forecast → Revenue stream forecast→ Decommissioning cost estimation→ Ratio of remaining revenue to decommissioning cost DCR → DCRV) can be applied to any other crude oil producing region.

Furthermore, this study adopted an interdisciplinary approach to establish a theoretical framework for sustainable decommissioning and abandonment of crude oil development infrastructure that is also applicable to other non-renewable natural resources. The framework encompasses knowledge and theories in petroleum resource production and associated rent forecasting, decommissioning liability and risk management, management of externality and environmental waste from petroleum development, and socioeconomic policy development and management elements. Based on these subjects and theories, it extended the frontier of knowledge by providing a comprehensive perspective to sustainable decommissioning of crude oil development facilities. Leveraging this theoretical framework, it developed a graded scale maturity model, described as the **Fairbanks Maturity Model**, which was demonstrated by using it to evaluate the readiness and gaps in sustainable decommissioning policy and strategy development for onshore crude oil fields in Nigeria.

The Fairbanks maturity scale can be deployed in any other region or corporation that is interested in achieving sustainable decommissioning of its oil fields or non-renewable natural resource assets. It will be useful for comparative evaluation, measurement and identification of gaps in national or corporate sustainable decommissioning policy, and strategy development and implementation. The results can in turn stimulate public discussions and participation, which is one of the key challenges with development of a sustainable decommissioning policy. Hopefully, the results will help governments to select fiscal policy elements that will engender sustainable decommissioning of oil fields and move from unsustainable decommissioning approach to a sustainable decommissioning approach (Figure 1).

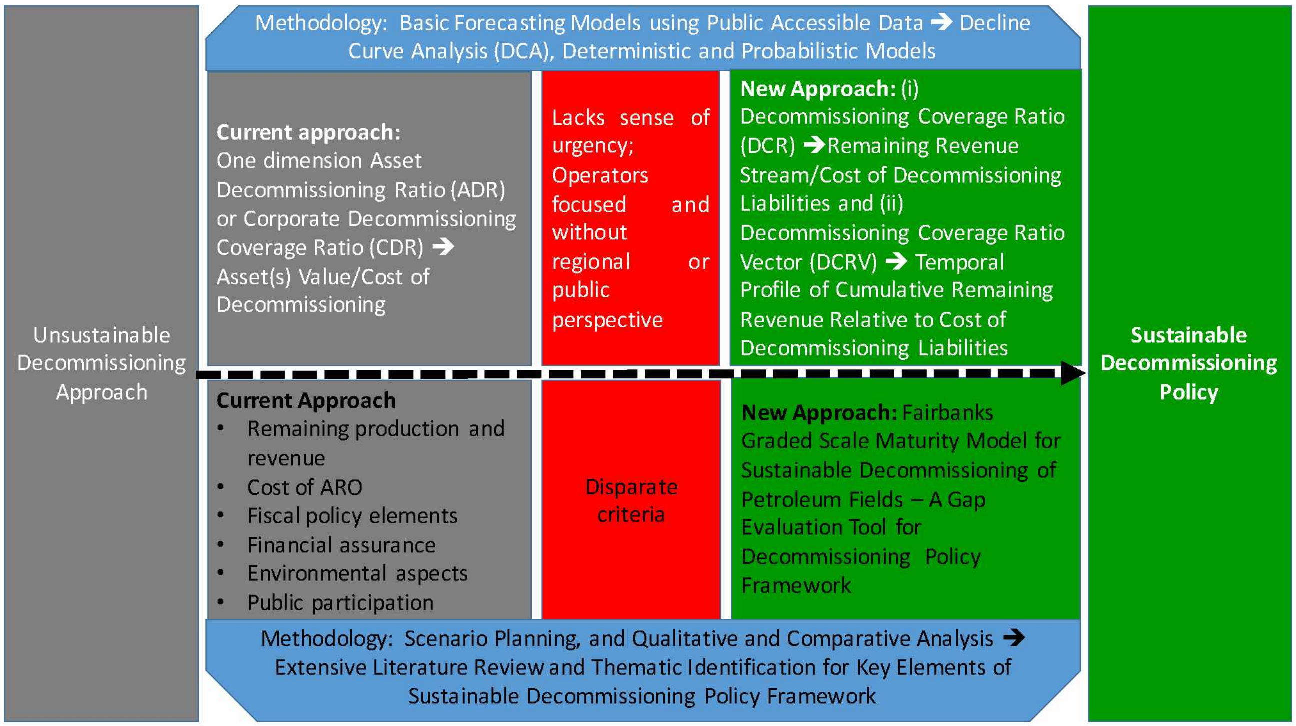


Figure 1: Research overview

This research contributes to knowledge in the areas of petroleum production forecasting, petroleum fiscal policy and economics, environmental engineering and sustainable approach to decommissioning, and indirectly to development and exploitation of non-renewable natural resources, as illustrated in Figure 1.

1.5. Structure of Report

To help with the dissemination of the research outcome and findings, this dissertation is structured into 10 chapters as shown in Figure 2.

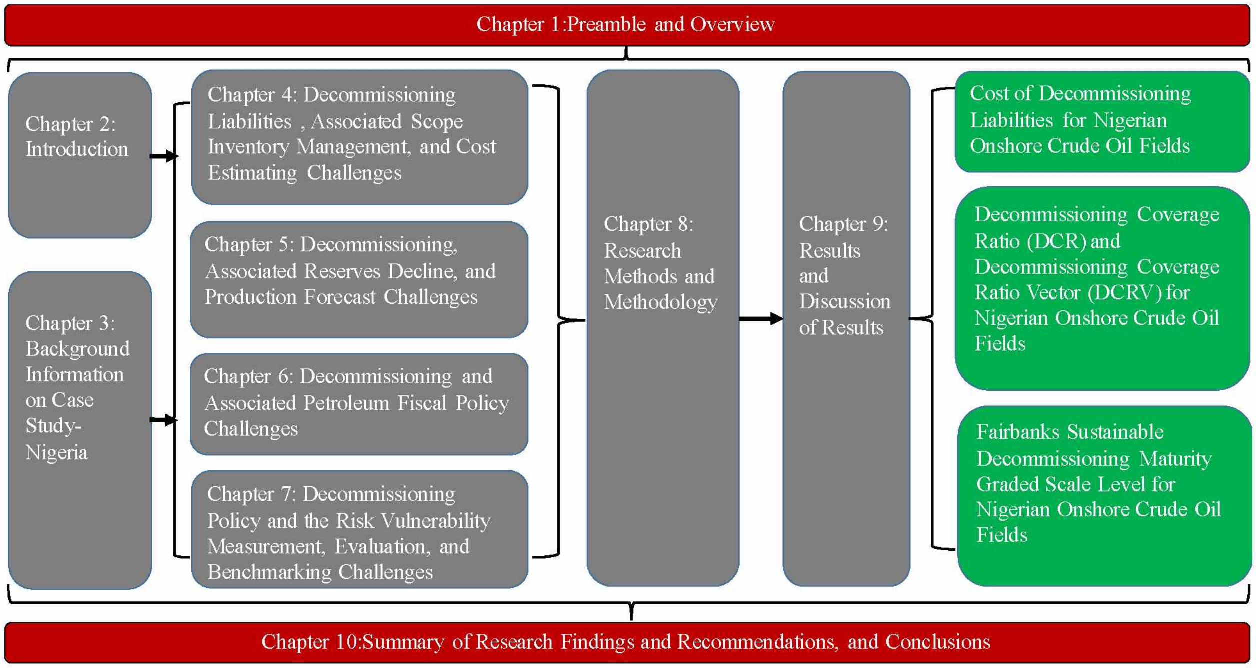


Figure 2: Structure of report

Chapter 1, which is the overview and preamble, encompasses the afore-discussed sections that attempt to succinctly describe the approach and expected outcome of the research, accruing benefits and significance, and structure of the report.

Chapters 2 and 3 set the stage by providing an introduction to the petroleum industry, socioeconomic environment, and political economy of petroleum in Nigeria as they relate to decommissioning, and the need for sustainable decommissioning framework for onshore field in Nigeria. In chapter 2, a delineating definition and taxonomy for decommissioning and abandonment is presented. A case was made for the focus of this study on onshore fields and ends with the isolation of challenges, perspectives, and topical issues with decommissioning and abandonment. It concluded by making a case for interdisciplinary approach to the problem of decommissioning of petroleum fields. Chapter 3 presents the political economy of Nigeria and relevant crude oil developmental trends, such as current reserves, production, consumption, and revenue trends, and Nigeria's population and economic growth aspirations, particularly as they relate to decommissioning and the future of crude oil production from onshore fields in Nigeria. It concluded that decommissioning is an important issue to the Nigerian petroleum industry that needs to be addressed and Nigerian onshore crude oil fields are good fit for the case study.

Taking a cue from the challenges, perspectives, and topical issues identified in chapter 2, chapters 4, 5, 6, and 7 present the theoretical and conceptual frameworks for sustainable decommissioning of onshore crude oilfields using Nigeria's onshore crude oil fields as a reference case study. The quantitative aspects of the study rely on the theoretical frameworks of petroleum engineering theories in reservoir engineering, reserves and production forecast, and engineering project management theories of scope scalability, cost estimation, and extrapolation. The qualitative aspects rely on the conceptual framework of risk management, natural resource and environmental engineering theories of common goods and management of externalities, and engineering management and public policy theories in capability measurement and evaluation, such as maturity models. These chapters present in-depth literature review and detailed theoretical focus on the identified elements of sustainable decommissioning to support the theoretical and conceptual framework for the study.

Chapter 4 discusses decommissioning of petroleum fields as a cost estimating and engineering project management issue. It examines the different theories and methodologies in cost estimating and project management as they relate to estimating the cost of decommissioning liabilities, using Nigeria onshore fields as a reference. It establishes a theoretical and conceptual framework that supports the need for a methodology that uses publicly available data on decommissioning of oil fields to determine the cost of decommissioning liabilities. It also establishes the existence of a reliable, public amenable and accessible inventory of assets, and cost estimate for their decommissioning liabilities as important elements of a sustainable decommissioning policy framework for petroleum fields.

Chapter 5 considers decommissioning from the perspective of estimating the size of petroleum resources that serve as the main driver and collateral behind resource development. It examines petroleum and reservoir engineering theories, such as petroleum development, reserve and production estimation, and production decline curve analysis, to undergird the conclusion that a sustainable decommissioning policy framework requires an element of reliable, public accessible, and interpretative remaining reserves and production forecast. It demonstrates the fit of a simple production decline model for estimation of the remaining production profile of Nigeria's onshore fields and its adequacy for policy development.

Chapter 6 examines decommissioning from the perspective of petroleum fiscal policy regimes. It focuses on theories and issues surrounding petroleum fiscal systems, how they affect the size of rent, and impact sustainable decommissioning of oil fields. It examines the proactive and reactive roles of financial assurance mechanisms to indirectly influence fiscal policy designs to achieve sustainable decommissioning of petroleum fields. It particularly identifies the need to have further granular focus on different revenue streams available to the government from the petroleum resource as a guide to policy decision choices for collateral against operators' default in meeting decommissioning liabilities.

Chapter 7 expounds on the theories behind decommissioning default risk from the perspective of decommissioning as an externality of the petroleum production cycle and the economics of internalization of externalities. It extends the review to evaluate a sustainable approach to internalization of decommissioning cost, the role of regulation, and importance of public participation to address decommissioning of crude oil fields. It concludes by making a case for publicly accessible and simple interpretative method of quantifying vulnerability to decommissioning default risk and benchmarking the level of preparedness for its mitigation or maturity of frameworks to address decommissioning, amongst entities.

Chapter 8 is a summary of the research methods and methodology. The research took several quantitative and qualitative approaches, such as decline curve analysis (DCA) models to generate future production, and deterministic and probabilistic models for future revenue stream profiles; fiscal system models for rent forecasting; scenario planning for plausible EOFL scenarios, and comparative analysis approach to identify the key elements for and gaps to effective sustainable decommissioning policy framework for Nigeria's onshore crude oil fields.

Chapter 9 is dedicated to the presentation of results from the DCA production forecast models, the deterministic and probabilistic models for different elements of petroleum rents, and the tableau of DCR and DCRV for onshore fields in Nigeria. The chapter also presents results from the Fairbanks maturity model evaluation of policy readiness and gaps in the existing sustainable decommissioning policy framework for Nigerian onshore crude oil fields.

Chapter 10, which is a summary of research findings, recommendations, and conclusions, discusses the results and research findings, and how they answered the research questions and met the earlier set research objectives. It also presents recommendations and suggested areas for further research.

2. Introduction – The Petroleum Industry and Sustainable Decommissioning

Petroleum mineral resources are finite, not renewable, and as such cannot be extracted in perpetuity. In most countries, several oil fields have entered the second half of the production profile and are already experiencing depletion. The International Energy Agency (2008) concluded that the average production-weighted decline rate globally was 6.7% for post-peak fields. It stood by this prediction in 2012, but revised it down marginally to 6.2% in 2013 (International Energy Agency, 2013). Simmons (2002) noted that sooner or later, most of the world's current population of giant fields will all decline.

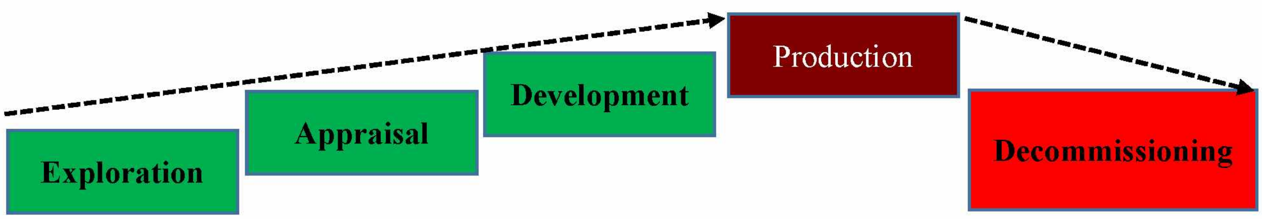


Figure 3: Exploration and production (E&P) opportunity development and maturation lifecycle

The petroleum business cycle runs from seismic works, field development, and production to eventual decommissioning and abandonment, when the field becomes unprofitable to produce (Figure 3). With old age, attendant maintenance and obsolescence challenges, associated production decline, and increasing environmental concerns, decommissioning and abandonment of oil fields have become very important activities in recent times. Considering UKCS, Rigzone (2010) reported an estimated expenditure of £30 billion (US $44.4 billion) over the next few decades on decommissioning of oil and gas platforms. In the GOM, triggered by new United States regulation, DecomWorld (2015) estimated decommissioning activities to cost approximately $26 billion.

Table 1: Public response programs to improperly abandoned petroleum field/facilities

Region	Name of Program	Size, Scope and Notes/Comments
Alberta Canada	Orphan Well Program	Circa $30million/year with about 69,000 orphan wells, excluding pipelines. In 2017, Orphan Well Associations, the industry trade body that manages the program, took a loan of $235 million (a 10-year loan) from the state government to plug abandoned wells.
Texas, the United States	Oil Fields Cleanup Program–State Managed Plugging and Cleanup Programs	$277 million since 1984 to plug 36,902 wells out of 43,035 wells approved for plugging under the program. $12 million was spent in 2017 to plug 918 wells. 2017 fiscal year budget of about $17 million. Funded via regulatory, permit and bond fees.
Saskatchewan, Canada	Saskatchewan Oil and gas Orphan Fund (SOGOF)	Funds collected from operators as orphan program fees based on the program's budget prorated according to percentage of deemed liabilities in the states. (Government of Saskatchewan, 2018)
Pennsylvania, the United States	Abandoned & Orphan Well Program	$33 million spent since 1989 on plugging of about 8832 wells. $1.03 million for 23 wells in 2016. State expects abandoned wells yet to be identified to be about 560,000. Funding is from permit surcharges on all permit applications for operations and each well.
Michigan State, the United States	Orphan Well Program	Started in 1984, it collects 2% of severance tax or at least $1 million/year from each operator for the orphan well fund.
Kansas State, the United States	Abandoned Oil & Gas Wellsite Remediation Program	About $35.1 million spent between 1997–2016 on plugging of approximately 9964 wells. It has inventory of about 21,734 orphan wells as on January 2018.
Wyoming State, the United States	Orphan Wells Program	In 2014, about 4573 abandoned wells at estimated plugging cost of $5000–$7000/wells.
Louisiana State, the United States	Oil Fields Site Restoration Program	$4.5 million per year. About 2306 wells plugged since 1993 at about $64 million. Funded via a fee of $0.015 per barrel of oil and condensate, and $0.003/thousand cubic feet of gas produced in the state.
Ohio State, the United States	Orphan Wells Program	Started in 1977 and currently has over 1000 orphan wells. Funded via a portion of state tax on oil and gas production.
California State, the United States	Idle Well Program	An idle well is well that has not been active for 24 consecutive months and every year, the state collects a fee per well. In 2017, there were 28,508 idle wells – total potential idle well fee of $16.59 million.
Nigeria, Onshore Region	None	None

Decommissioning could even become a basis for international conflict or war. Exarheas (2017) reported that in the discussions about Scotland's bid for self-governance, Scotland and the UK could go into dispute over who should assume ownership for decommissioning liabilities of North Sea oil fields. Johnson (2017) highlighted that the UK government could lose all of the remaining tax revenue from UKCS fields to payment for tax credits given to operators after successful completion of decommissioning of the fields. For example, in Texas, Kansas, and California in the United States, and Alberta in Canada, the governments have set up orphan well programs of several millions of dollars (Table 1) to deal with the huge challenges of proper decommissioning and restoration of abandoned petroleum development sites whose owners can no longer be traced and compelled to complete the decommissioning of oil wells (Alberta Energy Regulator, 2016; Department of Environmental Protection, 2017a; Department of Environmental Quality, 2018; Division of Oil, Gas & Geothermal Resources, 2018; Government of Saskatchewan, 2018; Hesson, 2006; Kansas Corporation Commission, 2018; Louisiana Department of Natural Resources, 2017; Ohio Department of Natural Resources, 2017; Railroad Commission of Texas, 2018;Wyoming Oil & Gas Conservation Commission, 2017).

Today, most giant fields globally, which includes fields in Nigeria, are already experiencing oil depletion, even though awareness about reserve depletion is low (Kamalu et al., 2015) and not a common public discussion topic in Nigeria in comparison to debates over equitable share of income from the fields. An optimist considers that more oil remains to be discovered in Nigeria, which is a cornucopian view to resources management. On the contrary, the Malthusian perspective submits that the peak oil typified by the maximum crude oil production rate has occurred and the resource is now gradually depleting. There could be controversies about peak oil and its effects. However, an uncontroversial fact to either the peak oil or cornucopian school of thought is that individual fields and wells do reach peak production, deplete, and will ultimately have to face decommissioning and abandonment.

For example, in Nigeria, MOCs are beginning to divest from Nigeria's onshore fields and selling their equity to local or small independent companies. Obasi (2013) observed an increasing trend of divestment by MOCs beginning from 2009, with almost 50% stake divestment as at 2013. Evidently, for the MOCs, the fields have become less attractive in the face of one or a combination of production, financial, and sociopolitical factors. Who will then be around to execute and pay for clean-up of the environment after the end of economic life of the onshore fields and facilities? Who will ensure that the environment, resource base, communities, and society is not left in a worse state than before oil production? Is it the MOCs, new local/independent companies, national oil company, government, local host communities, future generation unborn, or nobody? Can any proactive measure be taken now? Should it even be an issue? How is the risk measured and identified? These are sustainable development questions for the decommissioning phase and activities at the economic end of field lives of natural resources.

A cognitive interest that seeks for explaination of the nature of the problem of sustainable decommissioning and an action interest to find a method to better manage it (Baumgärtner et al., 2008; Khan, 2014; Ulrich, 2013; Wakeford, 2012) drives this research work. It involves theoretical, exploratory, and empirical evaluations of these questions that could also apply to other petroleum and non-renewable resource producing regions globally, even though this case study is based on Nigeria's onshore crude oil fields.

2.1. Petroleum Industry Taxonomies

The petroleum industry taxonomies are complicated and sometimes dependent on the objective of analysis or issue at focus. Some of the major schemes of classifications are based on positions in the value chain, operator's scope, territorial spread, ownership of operations, and location of fields and production facilities.

2.1.1. Classification Based on Value Chain

The petroleum industry can be classified with respect to its value chain, into three main sectors, (i) Upstream, (ii) Mid-stream, and (iii) Downstream as illustrated in Figure 4.

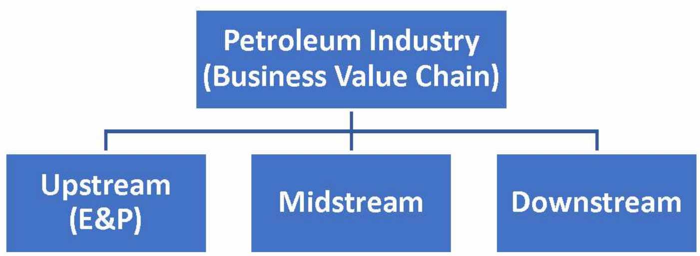


Figure 4: Petroleum taxonomy based on the industry's value chain

The upstream sector encompasses exploration and production (E&P) activities in the industry. This includes seismic and drilling activities, hydrocarbon gathering, and processing/conditioning activities done prior to the sale of crude oil or gas to refineries. Examples of upstream companies are E&P companies, such as ExxonMobil, Shell, ConocoPhillips, Statoil, and Chesapeake.

The mid-stream sector covers logistics activities between the petroleum fields and refineries or in some cases, end users. They are mostly focused on transportation of products. Examples are pipeline construction, maintenance and operation companies such as Alyeska Pipeline Service Company (Trans-Alaska Pipeline System), Pembina Pipeline Corporation, Sunoco Logistic Partners, and Petroleum Pipeline and Marketing Company of Nigeria.

The downstream sector refers to refining and gas conditioning activities that make the final products which end users utilize. They include refineries and gas distribution companies. For example, Warri Refinery and Petrochemical Company in Nigeria and Tesoro Refinery in Alaska. Similar to a typical food chain hierarchical pyramid, the upstream sector has more activities and spatial spread. For example, it has a larger number and spread of wells and facilities in comparison to the downstream sector with few refineries. However, the downstream sector directly impacts the society more than the upstream sector. Interestingly, the downstream sector is less in the news for sustainability issues in comparison to the upstream sector. As a result, it can be inferred that issues with the downstream sector are more sustainably handled and addressed in comparison to the upstream sector. In comparison to crude oil wells and facilities, the activities of refineries are not as remote from the society. For example, a refinery will not shut down without informing the local communities or without some form of community engagement as the effect on fuel supply may not take a long time to be felt by the society. However, a crude oil well can be shut without the local communities knowing, particularly if the local refineries do not depend on those wells for raw feed supplies. Due to its comparatively less direct interaction with society, the upstream sector has more challenges with comprehensive sociopolitical and environmental framework for sustainable development issues such as decommissioning of petroleum fields. This study focuses on the upstream sector with a hope to contribute towards closing gaps in the knowledge area of decommissioning of petroleum fields.

2.1.2. Classification Based on Operator's Scope

The petroleum industry can also be classified in terms of the operator's scope and spread along the value chain as shown in Figure 5.

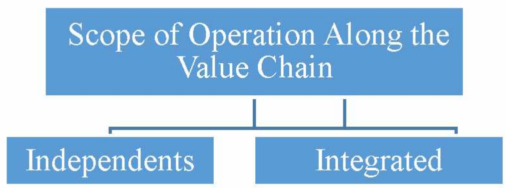


Figure 5: Petroleum taxonomy based on an operator's scope along the value chain

There are integrated operators who operate in more than one sector and independent operators who operate in only one sector. Some examples of integrated operators are Shell, ExxonMobil, and Chevron with exploration, exploitation, refining, and petroleum products marketing business units. Hilcorp Alaska LLC in Alaska for example, is an independent operator with only upstream business units. Some of the MOCs in Nigeria are globally integrated operators, but do participate in only the upstream sector in Nigeria. This study focuses on the decommissioning of petroleum fields and how the associated challenges could be exacerbated with the transfer of operatorship from large integrated operators to, in most cases, smaller independent operators.

2.1.3. Classification Based on Territorial Spread and Ownership

The petroleum industry can also be further classified into three sub-categories based on the geographical spread and ownership of business operations: (i) multinationals or international oil companies (MOCs or IOCs), (ii) local or indigenous companies or operators (LOCs) and (iii) national oil companies (NOCs), which is a peculiar group based on its ownership by sovereign governments, as illustrated in Figure 6.

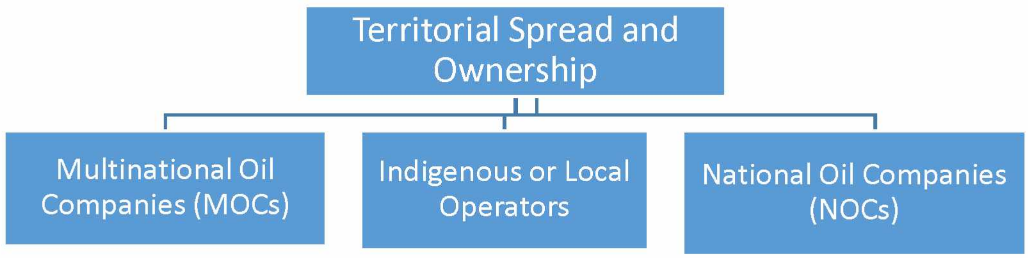


Figure 6: Petroleum taxonomy based on territorial spread and ownership

Large multinational oil companies (MOCs) or international oil companies (IOCs): They have large portfolios and are located in several nations and in most cases all continents. They operate as a global business entity or corporation with limited liability subsidiaries in several countries, such as Shell and ExxonMobil.

Local or indigenous oil companies (LOCs): They are operators with relatively smaller portfolios and most cases located in only one country. Some of them could have just only one field in their portfolio. They are owned or floated by some indigenes of the oil producing area/country. An example is Arctic Slope Regional Corporation Exploration LLC in Alaska or Seplat Petroleum Development Company in Nigeria.

National oil companies (NOCs): The key characteristic of companies in this group, is the government/public ownership of their business operations. They are most often based in the native country only. NOCs often do not run day-to-day operations of the fields, but enter into some form of partnership with MOCs or LOCs to operate the fields.

During the decommissioning phase of the petroleum life cycle, the MOCs will re-evaluate the economics of assets in their portfolio, and divest from and sell unattractive assets to smaller LOCs. For example, in recent times, the Nigerian oil industry has seen an increase in the number of small indigenous local operators. However, a larger percentage of the industry's business portfolio continues to reside with multinationals and national companies. The implication of this significant change in ownership structure that is rampant at the decommissioning phase is one of the foci of this study.

2.1.4. Classification Based on Location of Field and Producing Facilities

Another scheme of classification in the petroleum industry, but peculiar to the E&P sector, is a classification based on location of fields and facilities relative to the sea (Figure 7).

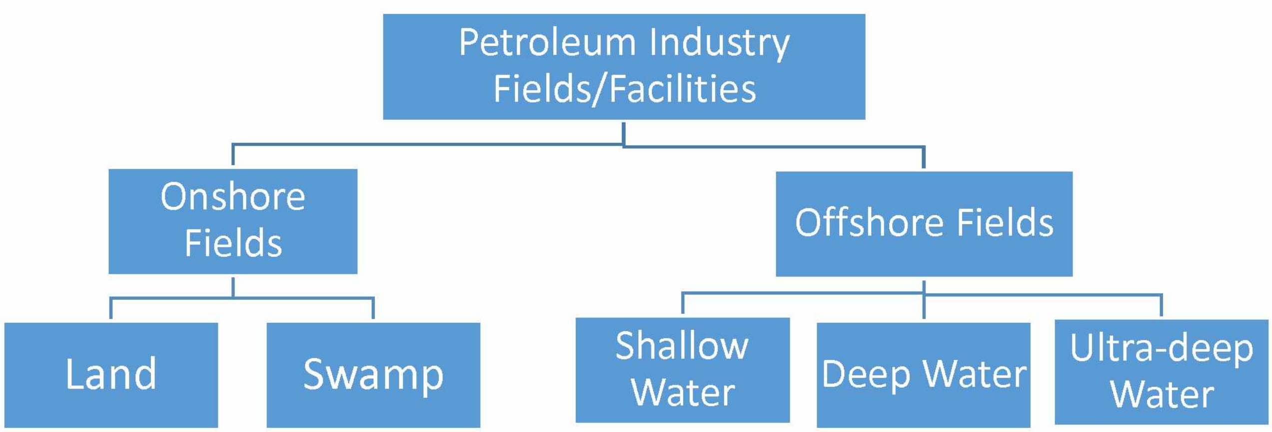


Figure 7: Petroleum taxonomy based on the location of field and production facilities

Petroleum fields in the E&P sector are classified as either onshore, shallow water offshore, deep water offshore, or ultra-deep water offshore fields, based on the location of the wells and facilities relative to the depth of the sea. In some countries like Nigeria, onshore fields are further broken done into swamp and land onshore fields. While the particular depth that delineates shallow water from offshore is not standardized, it is common knowledge that ultra-deep water fields are at depths of over 10,000 feet below sea level, deep water fields are at a depth of 1,000 feet to 10,000 feet, while shallow water fields are under a 1,000 feet below sea level. For the purpose of this research, petroleum fields will be classified into two broad categories, onshore fields and offshore fields, based on their location, either onshore (land and swamp) or offshore (shallow, deep, and ultra-deep water). Swamp fields in Nigeria are mostly on wetlands and swamp locations, less than 100 feet below sea level.

Typically, offshore fields decline faster than onshore fields. The economic life of onshore fields extends longer than that of offshore fields owing to the higher cost of offshore operations which incentivize the desire to recover invested capital quickly. A sizeable number of offshore fields are located in international waters and do impact international water routes. As such, their operations are also governed by international laws and legal frameworks. There have been instances of decommissioning projects executed for offshore infrastructures that faced complex operational, legal, and regulatory issues with bad results, such as the Brent spar decommissioning by Shell in the 1990s. Even though onshore fields are older, there are more offshore fields with decommissioning activities than onshore fields due to international regulations. Onshore fields mostly fall under national regulations and laws which are, at times, not enforced as there is no external pressure on the national government over its local laws. As a result, there is more in the body of knowledge for decommissioning of petroleum fields and infrastructure located offshore than those located onshore.

A clear delineation of the petroleum industry taxonomies is helpful in providing perspective to the characteristic behavior of different related stakeholders with respect to decommissioning and different types of decommissioning activities and strategies obtainable in the E&P sector of the industry. This study focuses on onshore fields, which has hitherto not attracted much academic research in comparison to offshore fields.

2.2. Petroleum E&P Maturity Life Cycle and Field Development Plan

In the petroleum industry, activities can be classified based on the position in the value chain (upstream, midstream, or downstream); operator's scope of activities along the value chain (integrated or independent); operator's geographic spread or ownership arrangement (multinational, local/indigenous, or state-owned/national), and location of operations (onshore or shallow offshore, near offshore, deep offshore, or ultra-deep offshore).

Irrespective of the taxonomy, the petroleum industry, particularly in the E&P sector, typically has similar phases and life cycles. Five phases can be identified in the E&P opportunity development and maturation lifecycle (Figure 3). They are exploration, appraisal, development, production, and decommissioning phases. Money is expended on the first two or three phases without any significant return on investment. The fourth phase – production phase, generates money from its activities. The last phase is the decommissioning phase, which in most cases, does not generate any net positive income (Figure 8). There are several in-depth researches on production, exploration, appraisal, and development phases. Comparatively, there are limited studies and research on the least income generating phase, which is the decommissioning and abandonment phase. Islam & Khan (2013), Lakhal et al. (2008), and Wood (2005) agreed that out of the lifecycle phases of a petroleum project development, the decommissioning phase gets the least attention or emphasis. This study delves into this phase of the petroleum E&P maturation lifecycle.

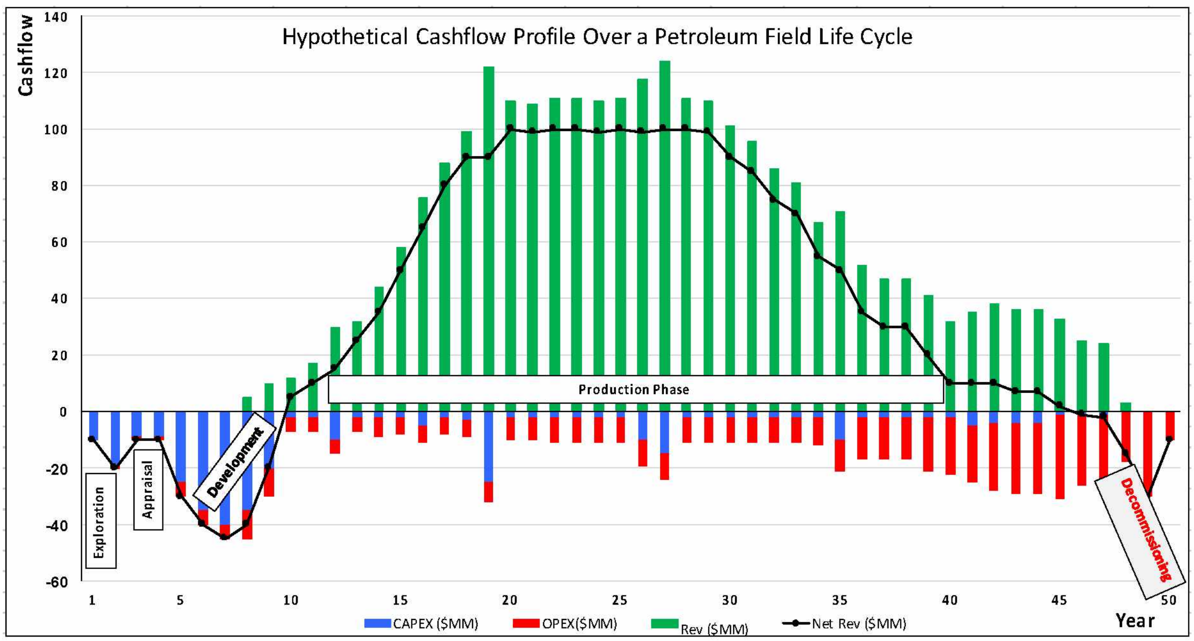


Figure 8: Petroleum E&P opportunity development lifecycle

2.3. Decommissioning and Abandonment – Definition and Description

Ruivo & Morooka (2001) defined decommissioning as "the dismantling, decontamination, and removal of process equipment and facility structures. It may be described as the best way to shut down production operation at the end of a field's life. This involves a multidisciplinary process, which requires detailed method [and] balance in several areas, e.g., environmental, financial, political, health and safety." Abandonment and decommissioning are often used interchangeably, even though according to Ayoade (2002), industry operators prefer to use decommissioning which unlike abandonment, does not connote voluntary relinquishment. Some operators refer to it as decommissioning, dismantlement, and restoration (DD&R), decommissioning, removal, and restoration (DR&R) or asset retirement obligations (ARO). The characteristics of decommissioning phase include consistent production decline from the assets, obsolescence of facilities without attendant upgrades, transfer of assets to smaller oil companies, bankruptcy, elopement, or dissolution of operating companies, and sociopolitical crisis.

Petroleum field development plans are supposed to include some consideration for field abandonment at the later life of the field when it becomes unprofitable. For the GOM and North Sea with several fields over 40–50 years and experiencing significant production decline, this has become apparent and no longer in the distant future, but a current reality. However, for some fields with anticipated peak production still in the future, operators and industry stakeholders may consider that decommissioning is scheduled for some time far out into the cloudy future. The dilemma is that in the lifecycle of the petroleum business, the oil production decline profile, which ends the active production phase, is characterized with increased expenditure, dwindling revenues, and increasing backlash from the externalities of the business.

The government and industry have focused more on policies, regulation, and strategies aimed at enhancing the active income generating phase of the petroleum field development business lifecycle (Figure 8). This is identifiable, not only in Nigeria, but amongst a greater percentage of oil producing nations. In contrast, attention on the decommissioning and abandonment phase is minimal and reactive. Vermont Law School, Institute for Energy and Environment (2010) in its white paper on Arctic offshore oil and gas guidelines, noted that the Arctic council devoted only a single page out of 79 pages to decommissioning. In Nigeria's legal and policy guidelines, it is haphazardly mentioned in different documents (Azaino, 2012; Dawodu, 2016; Lawal, 2008).

There is no comprehensive decommissioning policy document or practice for the petroleum industry in Nigeria. Decommissioning is mentioned almost in passing in comparison to elaborate sections on taxes, duties, and royalties.

2.3.1. The Brent Spar Incident and Awakening to Decommissioning

Prior to the late 1990s, decommissioning of facilities was not considered as important in the United Kingdom (the UK) or even elsewhere in the world. However, the experience of a field operator in the UK with the planned decommissioning of a spar buoy oil production facility in the North Sea, increased the importance of decommissioning to petroleum field investment. The adopted plan to decommission the facility generated protests from environmentalists and customers, and eventually influenced changes to government policy on decommissioning of oil and gas facilities in the UK. Instead of a proposed easy way to abandon the spar buoy, the operator has to opt for a more expensive concept after suffering unquantifiable damage to its reputation. Since then, decommissioning and abandonment has become a significant risk item to consider for every petroleum field investment.

The Canadian federal and regional governments have comprehensive and robust decommissioning polices and plans. They have agencies such as Alberta Energy Regulator (AER) in Alberta region, with oversight responsibilities for decommissioning. In the United States of America (the United States), there are several agencies with oversight responsibilities for different aspects of decommissioning and abandonment in the petroleum industry. For example, the Bureau of Safety and Environmental Enforcement (BSEE) has oversight for enforcement of safety and environmental regulations, which covers decommissioning in the United States Outer Continental Shelf (OCS). The Environmental Protection Agency (EPA) and the Bureau of Land Management (BLM) are other federal regulatory bodies with some oversight responsibilities for decommissioning and abandonment in the United States. In several states in the United States, there are different state government mandated regulatory agencies with oversight for decommissioning activities in the petroleum industry, such as the Department of Natural Resources (DNR) for the state of Alaska. In developing nations like Nigeria, Angola, Ghana, and to some extent the Middle East countries, there may be several identified regulatory agencies, albeit with unclear roles and responsibilities, for decommissioning activities in the petroleum industry. There seem to be as many different strategies as nations, locations, and situations toward the development of appropriate policy and management strategies for decommissioning and abandonment in the petroleum industry. However, a reoccurring factor in all these is that they are either onshore or offshore related with a greater portion focused on offshore operations. A coherent system of classification for decommissioning activities, particularly in relation to the industry taxonomy, is therefore necessary to appropriately delineate and investigate different decommissioning strategies adopted in the industry.

2.4. Taxonomy for Decommissioning in the Petroleum Industry

One of the rudimentary challenges with decommissioning in the petroleum industry is the ambiguous definition of different categories of decommissioning. The knowledge area is still evolving and the taxonomy of decommissioning and abandonment is still primordial (Fam et al., 2017; Kaiser, 2017).

Martin (2003) delineated decommissioning into onshore decommissioning and offshore decommissioning, while identifying separate legal frameworks for either category. For onshore decommissioning, the legal framework is determined by national laws and host government contracts, while offshore decommissioning, in addition to the above, has international and regional conventions as the basis for its legal framework.

Martin (2003) also provides a classification from the perspective of the location of decommissioning activities, offshore or onshore, irrespective of the original installed location of the facility being decommissioned. Offshore decommissioning was described as the part of decommissioning activities carried out at offshore locations for offshore field infrastructures. It includes offshore wells plugging, offshore pipeline decommissioning and abandonment, and dismantlement and toppling of rigs and platforms into the ocean to form artificial coral reefs, which in some places is done to enhance fishing activities.

Conversely, onshore decommissioning was described as a part of decommissioning activities carried out onshore for either onshore fields or offshore field infrastructures brought into onshore dockyards and metal scrap yards or some other offshore fields supporting infrastructure installed onshore. It includes dismantlement of facilities moved from offshore to a scrap metal yard located onshore, dismantlement of loading terminals, and onshore oil field facilities. In providing emphasis to disposal location, Chaplin (1997) described onshore decommissioning of offshore facilities as “the receipt [of] materials, waste management, methods of dismantling” and other activities to meet the requirements of the recipient onshore disposal facility. However, Oram (2011) described the handling of decommissioned inventory of scraps from offshore fields at an onshore disposal site as onshore disposal process and not necessarily onshore decommissioning.

In another perspective, Ayoade (2002) identified two types of decommissioning activities, onshore decommissioning and offshore decommissioning, which was based on the location of production operations, that is, either onshore or offshore locations. In expounding on decommissioning, Ayoade (2002) identified four stages within the decommissioning process, a detailed planning process to determine the options; cessation of operations and safe plugging of wells; removal of all or part of the installed facilities, and disposal or recycling of removed parts. Even though disposal was mentioned in further explanation, the location of the disposal site was not explicitly stated. Ayoade’s (2002) descriptions emphasized the location of production operation facilities being decommissioned, but did not specify the destination of dismantled items which could be offshore or onshore. Similarly, PetroWiki (2015) defined the “safe plugging of the hole in the earth’s surface and disposal of the equipment used in offshore oil production” as offshore decommissioning.

In all these descriptions, there are two leitmotivs—location of operations and location of disposal of wastes and scraps from decommissioning activities. The description of these classifications, except Ayoade's description, is biased toward the location of the disposal and dismantlement activities, which relegates the unique scope of decommissioning of onshore field installations. The effect of this description is evident in the lack of any unique call out of onshore field decommissioning activities in most literatures and the overlook of disposal locations and activities for offshore field decommissioning.

Willoch & Varebeg (2015) noted this ambiguity in the descriptions of the two classes of decommissioning and submit that one of the legal dilemmas with decommissioning in Norway resulted from this ambiguity. They observed that in Norway "it is generally assumed by many practitioners that onshore decommissioning of petroleum facilities is outside the scope of the Petroleum Act and that the law ceases to apply to such activities when the facility or equipment is removed from its offshore location." This has generated legal arguments that went high up to the Norwegian Supreme Court over the definition of boundaries of responsibilities and accountabilities for disposed items at onshore locations in Norway.

For the purpose of this study and as an element of the conceptual framework, decommissioning of oil fields will be classified into two major categories, offshore field decommissioning and onshore field decommissioning (Table 2). This definition is based on the original installed location, and includes the disposal location and other locations associated with decommissioning of the particular field. This is similar to the classifications suggested by Ayoade (2002), PetroWiki (2015), and Willoch & Varebeg (2015), but offers better clarity by calling out the particular type of field in the definition and encompassing all its associated decommissioning activities irrespective of the location of disposal. It will help this study to emphasize on the ownership of assets and associated decommissioning liabilities, irrespective of where the decommissioning activity takes place. This will help to direct attention toward onshore fields decommissioning, which in the long run will also help to reduce the number of orphan wells and facilities that could eventually become public liabilities.

2.4.1. Offshore Field and Onshore Field Decommissioning

Offshore field decommissioning will encompass all decommissioning activities for offshore field infrastructures either carried out offshore or onshore and whether installed onshore or offshore. In contrast, onshore fields decommissioning will encompass all decommissioning activities for onshore field infrastructures, which are most often carried out onshore. This will enable the focus to be placed on decommissioning of onshore fields, which constitute a greater percentage of oil fields in Nigeria that are in the decline phase or getting close to the end of their economic life. Offshore field decommissioning is governed by international, regional, and national legal regimes, such as international maritime organization (IMO) and United Nations convention on the law of the sea (UNCLOS). Comparatively, onshore field decommissioning activities are most often directly governed by national and local legal regimes and only remotely influenced by international or regional legal regimes. Apart from petroleum and local regulations, onshore field decommissioning activities are also underpinned by the national or local environmental and waste disposal management regulations (Table 2). Most of these regulations are based on the use of environmental laws, policies, and tools such as environmental impact assessment process.

Table 2: Comparison – Offshore field decommissioning and onshore field decommissioning

Factor	Offshore Field Decommissioning	Onshore Field Decommissioning
Original installed location	Offshore	Onshore
Legal governance framework	International and regional conventions and legal regimes	National and local laws
Basis for environmental regulation	International conventions and treaties that forces nations to comply	National environmental laws that are outside international jurisdictions
Perception of risk	Relatively higher – perceived to be more complex facilities, at a remote location, and attracts higher cost to properly complete decommissioning of its facilities	Relatively lower – perceived to be less complex facilities
Promptness to execute	Higher – more stringent regulation compels operators to be more prompt with decommissioning of offshore fields in comparison to onshore fields	Lower – less stringent regulation and consideration for marginal operations, incentivize procrastination of onshore fields decommissioning
Cost (direct execution cost)	Higher – remote location	Lower
Current operators and prevalent decommissioning strategy	Decommissioning done by MOCs using specialist engineering contractors	MOCs transfer assets to smaller oil companies who postpone decommissioning for a longer period
History of completed projects and body of knowledge	Globally, there are more visible and completed offshore decommissioning projects and more in the body of knowledge to learn from and use for benchmarking	Few fields and regions have been completely decommissioned, often rather mothballed. Less body of knowledge to learn from and use for benchmarking.
Potential for reputation damage	Higher – with international NGOs and outside national government controls	Lower – with local news under national government controls

Most of these regulations are based on the use of environmental laws, policies, and tools such as environmental impact assessment process. For offshore fields decommissioning, most of the regulations are based on international conventions and treaties which place obligation on the national laws to comply with such agreements.

Offshore field decommissioning activities appear to be more expensive and dangerous in comparison to onshore field decommissioning activities. The execution of decommissioning activities for offshore fields are relatively done promptly, when compared to onshore fields. Relative to onshore fields, decommissioning of offshore fields are not delayed much longer after the end of the economic life of a production platform. They are remote in the sea, but with high potential for international reputational damage if not done appropriately due to close scrutiny from international non-governmental organizations (NGOs) and stringent international governing conventions

In contrast, onshore field decommissioning activities are relatively less expensive, are not remotely located, and have relatively less execution risk. Therefore, they do not have sufficient incentives in terms of high cost, risk, and logistic challenges to be the top priority for operators. They can be delayed for a long time. The reputational damage if decommissioning of onshore fields is not properly completed could be managed locally or nationally. However, owing to its proximity to the public, there still exist some significant potential for onshore decommissioning projects to be scrutinized and monitored by a wider range of stakeholders, even during the post-decommissioning phase. This is where the ostrich-neck approach to onshore field decommissioning could be a short-sighted bad decision, particularly if not properly done.

2.4.2. Decommissioning of Onshore Fields: Technical Scope Description

As widely acclaimed and best practice, planning for decommissioning should start during the front-end loading or early phase of a field development plan. This may be 50 years or more before the actual decommissioning is executed. Unfortunately, according to Lawal (2008), it is recognized that development plans for over 50% of the world's existing petroleum fields did not consider decommissioning in their front-end loading or early stage. Decommissioning was not considered as an important aspect of the field development plan. Decommissioning and abandonment scope needs to be defined and included in the initial development plan. If the scope is neglected or poorly defined in the initial plan, there will be challenges in the decommissioning stage.

One key required element of scope definition for decommissioning phase at the planning stage of a field development plan, is the objective of the decommissioning process. The objective may be to restore the environment as much as possible to its pre-development state or to some agreed state which may include conversion of a site to another use. For example, onshore borrow pits can be converted to fish ponds. Similarly, for offshore fields, platforms may be converted to coral reefs or prisons. The scope of work for decommissioning can be broken down according to each element of the crude oil production system. There is a separate scope element for decommissioning and abandonment of wells, surface fluid handling facilities such as gathering stations, associated camps, pipelines, electric power and telecommunication infrastructure, roads, borrow pits, quarries, and surface reclamation. In addition, there is also considerable scope of work in the planning, design and engineering, logistics, waste handling, and disposal.

Another very important scope element is the management of residual liabilities during post-decommissioning of the fields. Residual liabilities could continue into perpetuity if the laws in the country of operation do not set a limit after which an operator is absolved of their post-decommissioning liabilities. A high-level description of the scope elements for onshore fields decommissioning is as follows:

(a.) Wells

- Isolation of reservoir and aquifers by a suitable barrier.
- Use of cement to plug well at the lowest freshwater aquifer.
- Disconnection and de-pressurization of flowlines.
- Removal of well surface equipment, wellhead, and wellhead appurtenances.
- Removal of well casing and tubing to a specified depth below ground level.
- Removal of well site foundations.
- Backfilling of remaining excavations.
- Marking of wells locations and maintenance of makers (residual liability).

(b.) Surface Fluid Handling Facilities and Camps

- Drain and purge hydrocarbon/chemical from process facilities such as vessels and tanks.
- Dismantlement and removal of process facilities.
- Dismantlement and removal of buildings, if necessary.
- Dismantlement of foundations and removal of debris to disposal site.
- Removal of gravels from pads and roads.

(c.) Pipeline

- Disconnection of pipelines from process facilities
- Drain and purge hydrocarbon from pipelines.

- Cutting of pipelines and supports to a specified depth below surface or ground level.
- Capping and burial or removal of pipe to disposal site.
- Update drawings and right of way maps.

(d.)Electrical Power and Communication Infrastructures

- De-energizing of cables and other infrastructures.
- Removal of all above surface cables, poles, and other infrastructures.
- Restoration of site to agreed state or pre-development condition.

(e.) Roads

If there is no agreement to transfer the roads to a third party or the public, the surface gravel and asphalt will be scrapped and removed to an acceptable depth. The roads will be backfilled using appropriate top soil to a specified thickness, graded, then re-seeded. In some cases, they will be scarified.

(f.) Borrow Pits and Quarries

- Dismantlement and removal of any surface infrastructure.
- Backfilling of pit to a specified standard.
- Landscaping and re-seeding as specified by the regulating agency.
- If it is agreed to convert the borrow pit to another use, the pits will be inspected and rehabilitated to an acceptable health and safety standard before handover for agreed use, such as conversion to a fish pond.

(g.)Transportation and Disposal

The logistic of transporting the dismantled items to an acceptable and appropriate disposal site is a key element of the scope of work. The proximity to a disposal site is therefore an important factor in the scope definition.

(h.)Planning and Engineering Support

Planning and engineering support has been recognized to be not as simple as "reverse engineering." It requires more complicated planning, design, and engineering to safely and optimally execute decommissioning. A good engineering plan could offer some economies of scale. Approval from several regulatory agencies could also be a tortuous process that needs to be adequately captured during the planning exercise. Comparatively, for offshore platforms, the sequence and timing of dismantlement and transportation of debris and scraps need to be aligned with tide movement and vessels availability.

(i.) Residual Liabilities and Post-Decommissioning Responsibilities

Post-decommissioning responsibilities, which may include continued monitoring, periodic third-party inspection, and assessment, may be required. For example, wells that are properly decommissioned and abandoned will have a low potential for fluid migration. The American Petroleum Institute (1993) recommends a 3-monthly monitoring for fluid level and pressure in the abandoned wells for 5 years and as needed thereafter. The maintenance of visible markers and other inventory identification instruments may also be required in perpetuity. Residual liabilities are of significant importance to stakeholders in the industry. The scope and liability could be large and a subject of complicated adjudication, such as the orphan wells problems in the United States. Orphan wells are wells whose owners are not available to properly abandon them either due to bankruptcy or as they cannot be traced (Table 1). Some of the orphan wells are wells abandoned several decades ago, but are now emitting hydrocarbons as they were not properly abandoned. The United States federal government, various state governments, and the public are now stuck with the re-plugging and abandonment responsibilities for these wells and sites. For most orphan wells program or similar programs, the current industry players have also been co-opted to contribute toward the cost of proper abandonment of these legacy wells (Feidt, 2012; Hesson, 2006; King & Valencia, 2014).

2.5. Challenges and Topical Issues with Decommissioning in the Petroleum Industry

Tularak et al. (2007) identified technical, environmental, legal, and financial challenges as the four main challenges to decommissioning. Rodrigues (2009) in his work with World Bank on sustainable decommissioning of oil fields and mines, identified decommissioning challenges to include environmental, legal, financial, social/public acceptance, and cross (disciplinary) issues. Ayoade (2002) identified regulations, environmental protection, economic matters, and politics as the critical and interwoven drivers for offshore decommissioning. Austin (2007) and Zhao et al. (2013) emphasized the environmental challenge, and viewed decommissioning and abandonment of oil and gas facilities as a major component of a company's drive to manage its environmental liabilities rather than a desired intrinsic objective. Extending responsibility to the governments and looking more at financial challenges, Pittard & Davitt (1998) noted that "to safeguard the environment and reduce the cost burden to the operators and in production sharing contract (PSC) regime countries, to the government themselves, governments must introduce fiscal relief regulations for abandonment costs." Pulsipher & Daniel (2000), and Van Dyke & Zobrist (2001) considered decommissioning from the challenges that regulatory agencies may face with getting accountable parties to properly complete decommissioning activities. They also examined the provisions of financial assurance to cover the cost for decommissioning and site restoration activities. Ayoade (2002) would rather place more emphasis on the legal and regulatory aspect and from an international law perspective for decommissioning offshore facilities instead of regulations for decommissioning of onshore facilities which he described as

“ relatively uncontroversial and governed by domestic laws.” Austin (2007) and similar authors who viewed decommissioning as a component of environmental liabilities, would argue that in developing countries, most environmental regulations are in the early stages of development and application, and are still controversial. Therefore, in developing countries, it does not matter if it is onshore or offshore decommissioning. There are still significant unresolved environmental, legal, and regulatory challenges associated with the end of life phase of petroleum production, particularly, decommissioning.

Interestingly and in a rather different direction, energy economist enthusiasts and some petroleum energy experts view the end of life phase of petroleum production from the perspective of energy economics rather than environmental or legal issues. Korpela (2006) and Jakobsson (2012) undertook extensive research on the production decline, depletion, and availability issues in the decline phase of oil fields. Kaiser (2015a), Kemp (1992), and Lohrenz (1991), linking energy economics to the financial implications of decommissioning, constrained the discussion more to tax and fiscal implications using offshore fields located at the United States GOM, UKCS, and Brazil as case studies.

While an absolute exhaustive literature search cannot be claimed, from investigation done for this study, there is no particular extant research work that focused on onshore fields decommissioning. In addition, most of the existing studies are silo approaches to the problem of decommissioning, which have hitherto yielded no comprehensive and satisfactory solution to sustainable decommissioning in the oil and gas industry. Decommissioning is related to oil depletion and can significantly affect society and the economy. Therefore, it is a trans and inter disciplinary problem requiring integration across different disciplines, such as petroleum engineering, environmental, social policy, and risk management, and cannot be "adequately tackled from the sphere of specific individual disciplines" (Max-Neef, 2005). This has contributed to failures to comprehensively address challenges with decommissioning of petroleum fields. For example, regulatory efforts have continued to struggle and in some cases, failed to adequately capture the cost of decommissioning liabilities, prepare for their occurrence, and consequently failed in managing decommissioning liabilities from the extractive industry (Feidt, 2012; Hesson, 2006). This is even worse in developing nations such as Nigeria with immature institutional and regulatory frameworks. Realizing these deficiencies, the World Bank instituted a study between 2006–2010 to investigate sustainable decommissioning practices for mines, oil, and gas facilities (World Bank, 2010).

According to World Bank (2010), one of the key challenges with sustainable decommissioning in the extractive industries in developing countries is generally "inexistent regulatory framework" for decommissioning. The World Bank further identified some of the priority issues for decommissioning policy development to include changes in government/regulations, accountability and responsibility, dependence of communities on benefits from the operational phase, and lack of technical guidance on social closure issues. While the World Bank study attempted to provide a set of high level guidelines to help nations handle decommissioning in extractive industries, it did not provide the practical steps on how nations could implement them to address the end of life phase issues associated with petroleum production. Countries with immature institutional capacities need concisely defined requirements/elements of a good regulatory framework for sustainable decommissioning, and simple and practical steps to address their gaps in meeting these requirements. For example, the World Bank study did not identify how nations and public stakeholders in developing nations can estimate the size and cost of decommissioning liabilities within the limitations of institutional frameworks in developing nations. It did not provide an appropriate methodology for nations or regions in developing countries to understand their vulnerabilities to decommissioning liabilities and how they can be appropriately benchmarked with other regions or nations. Lack of information leads to ineffective stakeholders' participation, which in turn leads to poor public policy development for a public and sustainability issue such as decommissioning of petroleum fields. Therefore, these issues are important to sustainable decommissioning of petroleum fields, particularly in developing nations. While developing nations may rely on the international regulatory and legal frameworks governing international water bodies for decommissioning of offshore fields, onshore fields decommissioning do not have that privilege. Onshore fields decommissioning relies on national regulatory and legal frameworks, which for most developing nations, are deficient. An explicit and simple method to determine the cost of decommissioning liabilities and evaluate government's vulnerability to risk of an operator's failure to properly complete decommissioning of its fields, will be helpful to public stakeholders in developing nations in particular and the petroleum industry in general.

2.6. Decommissioning from a Sustainable Development Perspective

One important requirement for sustainable decommissioning, as identified in most discussions on decommissioning, is the identification and appropriation of accountable parties for the cost of decommissioning and associated financial liabilities at the end of a field's economic life. Crude oil, similar to most non-renewable natural resources, is a common pool resource in most countries and almost all developing nations. Decommissioning of its associated facilities can also be viewed as a major waste generating phase of the crude oil value chain. As a result, financial liabilities for decommissioning, similar to most environmental waste and externalities issues in natural resource economics, is closely tied to the seminal topic of intergenerational equity, inter-temporal efficiency, distributive justice, and sustainable development. These seminal topics form a significant portion of foundational theories and theoretical framework for sustainable management of natural resources, such as natural forest and coal. Considering petroleum as a natural non-renewable resource, decommissioning and abandonment strategy for its facilities would also be underpinned by these seminal issues, and therefore a sustainable development problem.

Sustainable development has become a popular mantra for human development in the 21st century and the petroleum industry is much at the center of it. The industry is one of the producers of non-renewable energy which has been associated with contributory factors to non-sustainable development. Harris & Khare (2002), and Nortjé et al. (2014) noted that over the last few years, concerns over sustainable development has become increasingly important in the petroleum industry. Weaver (2003) observed that sustainable development has become important to the industry due to the "painful legacy of pollution and poverty often left by the extractive industries in developing countries in the past and [its adoption as] a beam of light pointing to a brighter future." Schneider et al. (2013) undertook a benchmarking study on the efforts being made by the oil and gas sector toward sustainability, and opined that oil and gas companies have taken steps toward better sustainability or sustainable development in recent years. Escobar & Vredenburg (2011) had earlier disagreed with this positive trend of advancement suggested by

Schneider et al. (2013). In their perspective, the resemblance of sustainable development practices being seen amongst oil and gas companies is based on mimetic isomorphism, which is a slow, rare, isolated, and discretionary process. This is contrary to normative and coercive isomorphism which is the desired way to drive the adoption of sustainable development from a holistic, non-discretionary, and culture change perspective. Meadows (1998) espoused that one of the ways to drive this culture change is to have clear and usable indicators for sustainable development, which could be conceptually extended to sustainable decommissioning. Therefore, measuring advancement toward sustainable development is very important to the debate and implementation of sustainable development policies in the petroleum industry.

Elkington (1997) and Elkington (2004) proposed the triple bottom line (TBL) concept of sustainable development in which economic prosperity, environmental quality, and social justice can be balanced. TBL as a basis for accountability in sustainable development is widely supported in government, public, and industrial development circles. However, Ibanez (2011) noted that the "issue of sustainability may not altogether be readily evident in decommissioning" considering that it is at the end of the economic life of a field, when comparatively, there is no handsome net income. Nevertheless, there are several direct and subtle links between decommissioning and economic prosperity, environmental quality, social justice, and multi-stakeholders/multi-interest dilemmas experienced at the end of the economic life of a petroleum field. Ibanez (2011) concluded that the "principles of sustainable development should frame and guide the decommissioning process." Following Meadows (1998), the focus is to define clear and usable indicators that will adequately represent the intergenerational and inter-temporal equity issues, and other sustainability development issues associated with decommissioning.

Sustainable development principles submit that each generation should not use endowed natural resources in a way that cheats successive generations or mismanage them inefficiently in the overall comparison between generations. An efficient resource-use policy will adopt a management decision objective that maximizes the net benefit from the resource over time. For example, if in a known future, crude oil will for sure become “a cheap commodity” in constant money terms, it may be beneficial to sell the entire reserve today, complete decommissioning of the facilities today, and invest the money in a more attractive investment for future generations instead of just leaving the crude oil in the ground. Therefore, it means that the cost of decommissioning should not be disproportionally borne by one generation, particularly in relation to the benefits it enjoyed from the natural resource. Future generations should not be made to pay for decommissioning of the oil fields they did not benefit from or benefited less in comparison to the present generation.

Therefore, the question extends to the proportionality of the liability to the benefits received by each generation. This can be understood from the polluter’s pay principle of sustainable development and distributive justice. A proactive objective will be to ensure that one generation is not positioned to over-produce to the detriment of future generations by taking advantage of market failures of today. For example, a failure to capture the cost of decommissioning as part of today’s actual total crude oil production cost could translate into an operator having a production cost lower than the social cost. This could incentivize over production, which makes decommissioning to be a market externality problem. Capturing the cost of decommissioning in today’s operational cost will incentivize pareto optimal production and reduce cheating future generations, which will be in line with the principle of sustainable use of natural resources.

The dilemma is in identifying the criteria and measures to be used to allocate and determine the benefits and liabilities per generation. There have been arguments about how equity should be determined. Some experts propose the use of discounting methods, which are rebutted with the questions of whose discounting value should be chosen. Others have proposed social discounting factors. Auty & Mikessell (1998) submitted that sustainable development requires savings and investments of social capital at a rate that replaces the natural resource capital being exploited. It is a complex argument. However, it has to start from a comprehensive, satisfactory, and dynamic estimate of the size of the resources and liabilities. The common foundation needed for successful and sustainable management of natural resources for intergenerational and inter-temporal efficiency will therefore include adequate and reliable accounting of benefits (natural resource stocks) and liabilities. Ordinarily, this will be data intensive, which is one of the reasons identified for poor public policy development in environmental issues, such as decommissioning, particularly in developing countries (Bell & Russel, 2002; Jörgens, 2012; World Bank, 2010).

Generally, in the petroleum industry, there is significant information asymmetry in favor of the oil companies. The details of production volumes and cost are kept as trade secrets by the oil companies and even the government has limited access to some of these pieces of information (Sheppard, 2017). However, while granular data may be elusive at the individual field level, aggregate data at some higher level, for instance national or regional level, may not be as elusive due to business requirements that already mandate periodic public disclosure of financial reports. Therefore, data aggregation could provide a solution to the high data intensity requirements and challenges associated with decommissioning policy development in the petroleum industry.

2.7. Proposition – Onshore Fields Decommissioning and Interdisciplinary Approach

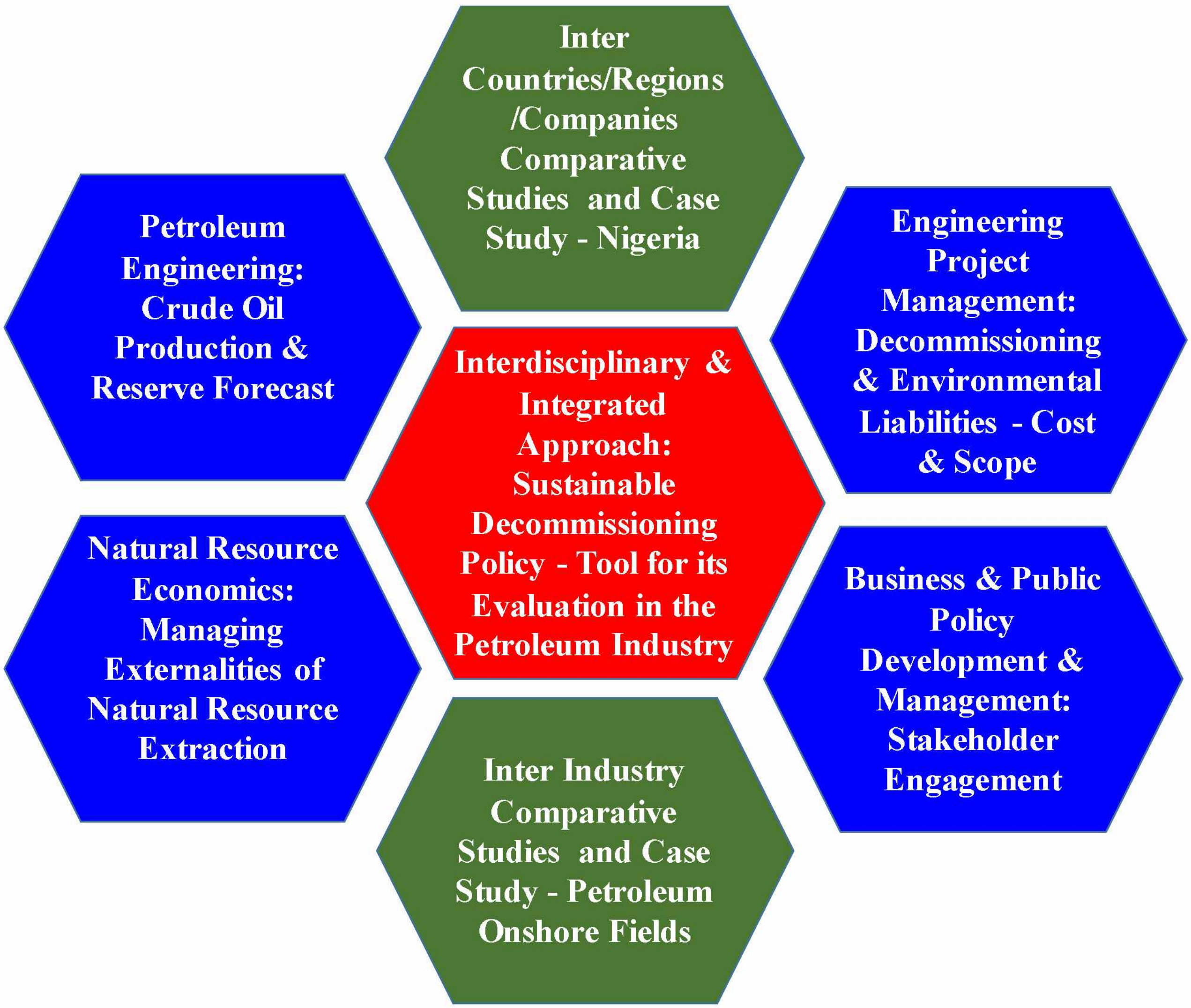


Figure 9: Interdisciplinary areas for decommissioning

Considering the afore discussed factors, this research will take a position that a reliable and suitable method of accounting for hydrocarbon stock and cost/liability of decommissioning is necessary for the successful development and management of a sustainable decommissioning policy for petroleum fields in any country, region, or entity. For some petroleum producing regions with discrete boundaries and operational characteristics like Nigerian onshore fields, instead of a data challenged granular assessment of individual fields, an aggregate and collective assessment of several fields at the regional level will provide adequate information for the evaluation of sustainable decommissioning policy development. Furthermore, from the previous discussions, “the complexity of issues in a decommissioning process requires a multidisciplinary and integrated approach” (Environmental Resources Management, 2009; Fjellsa, 1996; Max-Neef, 2005; Ulrich, 2013; Wakeford, 2012). While this may be applicable to both offshore and onshore fields, it is even more pertinent for onshore fields that are relatively less studied. Therefore, the theoretical framework for a research in policy development for decommissioning of onshore oil fields is interdisciplinary, as illustrated in Figure 9. It involves the application of knowledge, theories, and techniques in the discipline of (i) petroleum engineering – production decline theories and estimation of size of rent, resources, reserves, and reserves changes among others, (ii) project and engineering management – risk and liability assessment, including definition and estimation of cost and risk of liabilities associated with decommissioning, (iii) natural resource economics – fiscal measures and management of decommissioning as externalities of crude oil production through the use of predictive indicators associated with decommissioning risk, and (iv) public policy development and management – public participation in policy development. These could be applied with a particular focus on either onshore and offshore field decommissioning, or a particular focus on a specific location.

In summary, there is a case for the petroleum industry and national/local governments to proactively work toward sustainable decommissioning of oil and gas fields, particularly onshore fields that are not under existing international regulatory frameworks and conventions for decommissioning of petroleum facilities. However, how can nations or entities come to a realization that decommissioning of oil and gas facilities/fields is a problem? With information asymmetry in the industry biased in favor of oil companies, how can resource policy managers and public stakeholders identify the cost of decommissioning liabilities, the future resources that underwrite these liabilities, and the vulnerability of the public to bear this cost? How can policy elements be managed toward an equitable intergenerational and inter-temporal distribution of decommissioning responsibilities? A foundational requirement for sustainable decommissioning policy development and preparedness will include knowledge of the cost of decommissioning liabilities and the size of collateral provided by available resources. It will also include clear and usable indicators of some form to measure progress or identify gaps toward a culture change that will ensure environmental and societal well-being and intergenerational equity. There is a need for a simple but adequate method to determine (i) the cost of decommissioning liabilities from petroleum fields, (ii) the value of the remaining resource that support these fields and provide collateral for their liabilities, and (iii) exposure to the associated risk of an operator's default to meet its decommissioning liabilities, particularly in developing countries, such as Nigeria. Along with these, a framework of simple and clear indicators for benchmarking and gap analysis for sustainable decommissioning is also needed. These needs cut across several disciplines and therefore require an interdisciplinary approach.

3. Trends and Implications for Decommissioning of Nigerian Onshore Petroleum Fields

After the decline of production from onshore crude oil fields in Nigeria, will there be any organizational structure in place to restore the environment back to its pre-development or a generally acceptable condition? If there is a structure, will it be left with toxic assets such that Nigeria will be unable to effectively restore the environment back to its pre-developemnt state?

Ite et al. (2013)

Figure 10: Map of Nigeria showing the Niger Delta onshore region

Nigeria is located in the western coast of the sub-Saharan Africa. It is bounded on the west by the Republic of Benin, in the east by Cameroun, and in the north by Niger Republic (Figures 10 and 11). Nigeria gained independence from Britain in 1960, when the country's population was approximately 45 million and the gross domestic product (GDP) was $4.2 billion. The estimated population in 2016 was 186 million, a 305% growth since its independence from Britain in 1960, and the GDP in 2016 was $405 billion (World Bank, 2017).

Its population is one of the fastest growing and the seventh largest population in the world. Nigeria has a large arable land for farming and animal husbandry. Its geology bequeathed several natural and mineral resources to the Nigerians. It is reported to have economic quantities of mineral resources, such as coal, gold, gypsum, and tin, apart from petroleum.

Lemke et al. (2010)

Figure 11: Map showing crude oil infrastructure spread across the Nigerian onshore region

According to the United States Energy Information Administration (2016) report, with 2.3 million barrels per day crude oil production, Nigeria was the largest producer of total petroleum and other liquids in Africa in 2015. Nigeria holds an estimated crude oil reserve of approximately 37 billion barrels, the 11th largest crude oil reserve in the world (" Worldwide Look, " 2014). It also holds the ninth largest gas reserve in the world, estimated to be approximately 180 trillion scf. Before oil discovery in 1956, Nigeria used to produce and export agricultural products such as palm oil and groundnut, and minerals resources such as coal and gold. In 1956, Nigeria produced approximately 790,030 tons of coal and average of approximately 600,000 ton per year in the 1960s (Odesola et al., 2013). These were the significant foreign exchange earners for the country. Toward the end of the 1960s, coal production started to decline due to geological and economic factors. Coal mining and related activities have currently declined to a non-significant level in Nigeria. The abandoned coal mines have left problems of open mine pits, landslides, and a ghost town economy for the host communities (Ezemokwe & Maduibuike, 2015; International Centre for Investigative Reporting, 2017; Obiadi et al., 2016; Odesola et al., 2013; Ogbonna et al., 2015). Agricultural produce was also another major foreign earner for Nigeria in the 1960s. According to Ahungwa et al. (2014), agriculture contributed to 61% of Nigeria's GDP in 1960-1964 and was a major employer of labor both directly and from derivative industries. Due to several factors, Nigeria is now a net importer of food and agricultural products. The farms have been either abandoned/un-kept or converted into other use. The boom economies associated with coal and farming have become ghost and anemic economies with no sustainable future.

Currently, crude oil is the major foreign exchange earner and backbone of the economy. With a decline in production volumes from onshore fields and increase in technical, sociopolitical, and global economic difficulties with the crude oil economy, will the petroleum infrastructures and associated socioeconomic environment follow the same outcomes witnessed by the decline of coal and farming in Nigeria? Can the crude oil decline be proactively managed differently? Are there signs to watch out for?

3.1. The Nigerian Economy

Nigeria, with its economy of approximately $405 billion, can be classified as a middle-income country and an emerging economy based on the consistent growth of its economy. Sanusi (2010) divided the economy into "three major sectors namely primary – agriculture and natural resources; secondary – processing and manufacturing; and tertiary/services sectors." In terms of its contribution to Nigeria's GDP, agriculture has seen a decrease from over 60% in 1960 to about 40% in 2015. Conversely, the natural resource sector which is dominated by petroleum and mining industries grew from 11% to almost 30% over the same period and the petroleum industry is the major contributor to the GDP associated with the mining sector (Sanusi, 2010). KPMG (2014) described it as "the single most important sector" in the Nigerian economy yielding 90% of foreign earnings and 80% of the government's revenue.

To sustain this stream of income, the rate of development and expanse of footprint in the upstream sector is very large. Therefore, a decline in oil and gas production will have a significant impact on the government's revenue and socio-political stability of the nation. Empirical data already suggests a significant drop in crude oil production, particularly from onshore fields. According to Heritage Oil PLC (2013), crude oil production from the large onshore fields in OML-30, as at 2012, has declined by approximately 86% from peak production of 280 Mbopd in 1971 to circa 30 Mbopd.

3.2. The Petroleum Industry in Nigeria

Crude oil was discovered by Shell-BP in commercial quantities at Olobiri in Bayelsa State, Niger Delta onshore region of Nigeria in 1956 with a 5,100 bbl/d production recorded in

1958. Several years later, the industry in Nigeria as at 2010 has about 500 production fields (National Petroleum Investment Management Services (NAPIMS), 2010) with over 55% of them reported to be onshore (Onwuka, 2011). According to NAPIMS, as at 2010, approximately 5,284 wells have been drilled in mostly the Niger Delta region in Nigeria (Figure 11). Gboyega et al. (2011) observed that there are over 3,446 active wells in Nigeria, which suggests circa 40% non-active wells left at different stages of decommissioning. As at end of 2015, Nigerian production was approximately 2.3 million bbl/day with a reserve estimate of 37 billion barrels. The country's aspiration is to attain a production rate of 4 million bbl/day and grow the reserve base to 40 billion barrels by 2020 (Alison-Madueke, 2013).

3.2.1. Organizational Structure of the Petroleum Industry in Nigeria

The petroleum industry in Nigeria is dominated by the upstream sector. The downstream sector is relatively small and the midstream sector is just emerging. Owing to the structural arrangement where most of the operations are owned by multinational companies and the government, the midstream sector is very small. The existing pipeline, storage, and processing companies are owned by upstream or downstream sector players as their subsidiary companies.

Consequently, there are few independent pipelines or logistic companies in Nigeria. Natural gas utilization in Nigeria is very low and there are few domestic gas distribution pipeline networks in Nigeria. In addition, these networks are managed almost like units under companies in the downstream or upstream sector. KPMG (2014) observed that the "mid-stream operations are usually included in the downstream sector" and attempts to distinguish the two sectors is just beginning in Nigeria.

The downstream sector is dominated by four refineries, one each in Warri and Kaduna, and two in Port Harcourt. These refineries owned by the government through public corporation, NNPC, were built between 1963 and 1989. They have a combined capacity of 505,000 bbl/day, but have been operating at less than 30% of installed capacity for several years. The country aspires to have more refineries installed by private entities. There is also the liquefied natural gas (LNG) plant at Bonny, which is also a key part of the downstream sector. It produces about 22 million tons per annum from its six trains. This plant, which was built between 1996 and 2007, is relatively new. With an increase and un-met demand for hydrocarbon energy products in Nigeria, even with the decline in crude oil production, investors may still want to use the refineries and LNG plant for petroleum importation. An LNG plant can be reversed for LNG importation (Shaw Alaska Inc, 2006). Moreover, Nigeria's gas reserves are relatively still large. That notwithstanding, decommissioning of these facilities at the end of their economic lives is important. Nevertheless, for the purpose of this study and to achieve focus, emphasis will not be placed on decommissioning of the downstream sector facilities.

The upstream sector has more infrastructure, activities, and assets in comparison to the downstream sector in Nigeria. It includes well heads, well tubing and liners, vessels and processing equipment, pipelines/flowlines and export pumps, gathering facilities, camps, roads, power, utilities, and other supporting infrastructures. It can be further divided into onshore and offshore sectors based on location of the fields (Figures 7 and 12). Production handling facilities are installed on either the platform, if it is an offshore location, or on surface gravel pads, if it is an onshore location. Unlike offshore locations where installations are closely clustered around a platform, Nigerian onshore fields are spatially dispersed and widespread with vast pipeline and flowline networks. Most of the onshore field infrastructure and gathering facilities were manufactured, fabricated, and installed in the late 1950s and 1960s. The facilities are getting old and in some cases, obsolescence has set in. Without some viable and exciting economic prospects on the horizon for these fields, an upgrade or change-out of the infrastructure may not be supported. They may be kept mothballed, waiting for eventual decommissioning in the future.

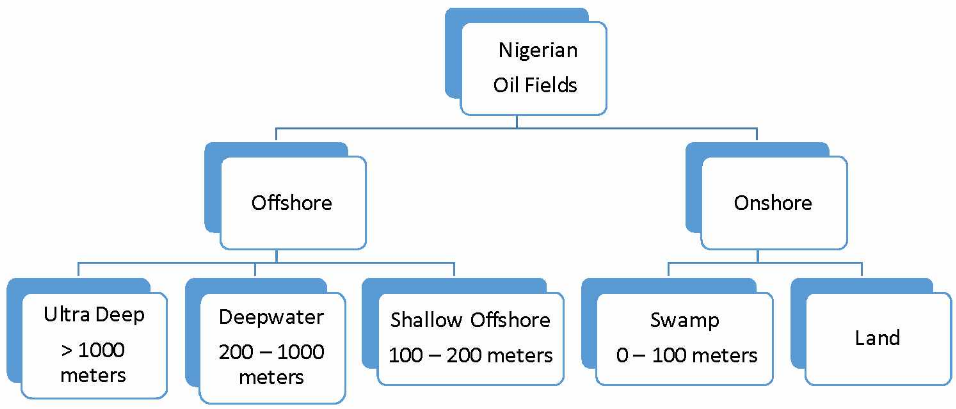


Chart prepared based on data from www.NAPIMS.com/fiscal.html

Figure 12: Nigerian oil fields structure

Most of the onshore facilities in Nigeria share similar designs and were installed in standard sizes of 30 Mbopd and 60 Mbopd capacities or similar scalable capacities. They were installed at a time when only two or three major operators were in Nigeria, and a larger percentage were installed by one operator for the entire onshore region. Currently, even though there are several operators in the region, it can be assumed that all the facilities will fall under some form of standard categories of capacity and hardware, and would therefore have similar and scalable decommissioning scope of work.

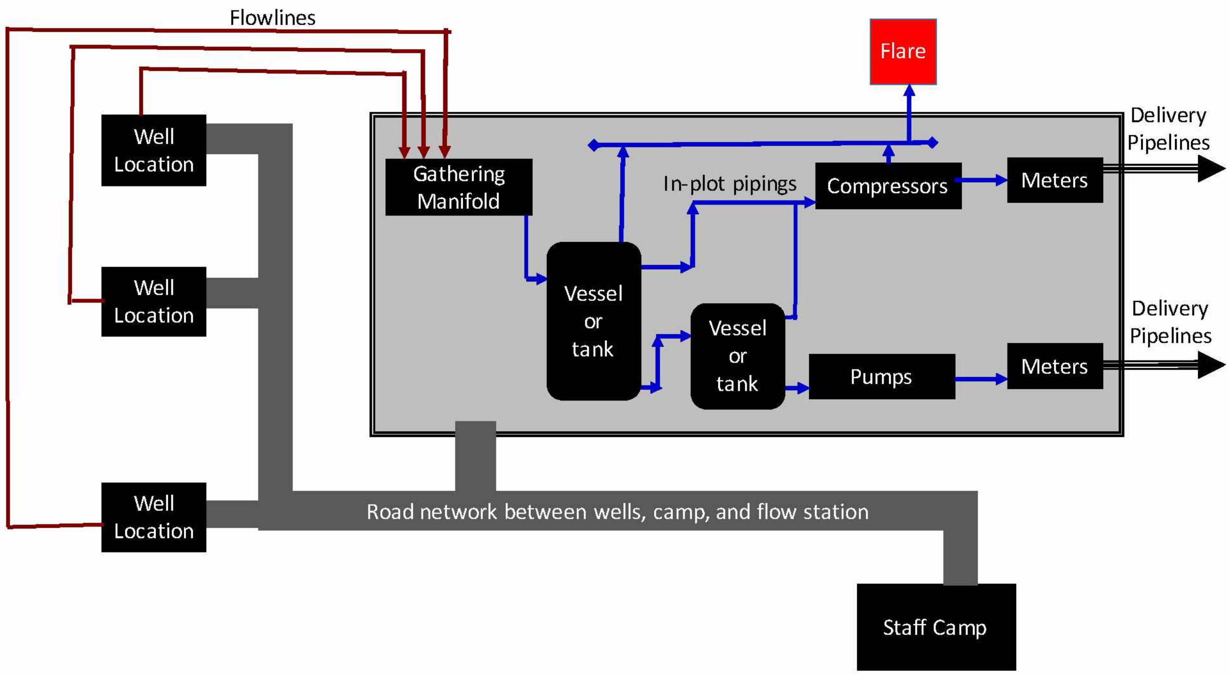


Figure 13: Illustration of decommissioning scope of work elements for a typical flowstation and support infrastructure

There are approximately 100 gathering facilities or flowstations scattered over land and shallow swamp locations in the Niger Delta region (Figure 11). Typically, each field has flowlines running from each well location to manifolds at a gathering station often described as a flowstation. A gathering facility may serve more than one field and is the nucleus of activities and operations for the fields it serves. Flowlines are a network of steel pipelines that connect the wells to the gathering manifold in the flowstation. The gathering manifold is a collection pipe with connection points for each flowline from the wells. It transfers crude oil into separation vessels, which are holding tanks at the flowstation. There are different vessels and associated equipment at the flowstation that hold the crude oil for processing before it is sent by the pumps through a delivery pipeline to the terminal for sale (Figure 13).

At the flowstation, there are in-plot piping sections connecting vessels, and crude oil metering and pumping facilities. Some of these facilities have gas compression equipment for lift gas compression. A compressor takes gas coming from a vessel at low pressure and compresses it to a higher pressure suitable to be injected into the reservoir to push out more crude oil from the reservoir to the surface. The number of wells, size of well pads, and associated length of flowlines, which may be severally scattered around a large expanse of land and swamp locations, vary with each field. Associated with each field may also be several road networks, staff camps, and open borrow pits used for road construction. A flowstation is the hub for all activities, infrastructures, and facilities needed to operate a field or group of fields. For the purpose of this evaluation, the decommissioning scope of work for each flowstation will be assumed to encompass decommissioning of all its associated facilities and supporting infrastructure. A flowstation will be a good assumed unit of scope of work for decommissioning of onshore fields in Nigeria.

The vast spread of these upstream assets poses a significant challenge to optimal decommissioning in terms of cost, project plan, regulation, and environmental sustainability, which furthermore makes the onshore fields in the upstream sector a pertinent area to direct the focus of this research.

3.2.2. Ownership and Operatorship in the Nigerian Petroleum Industry

Operatorship in the upstream sector of the petroleum industry in Nigeria can be broken down along the lines of NOC, IOCs (also described as MOCs) and LOCs. The LOCs include big indigenous oil companies and the emerging indigenous marginal field oil companies or producers. The NOC is NNPC with its producing subsidiary, the National Petroleum Development Company of Nigeria (NPDC) and its other units, such as the investment management agency, NAPIMS.

MOCs: The MOCs or IOCs include multinational companies, such as Shell, Agip, Total, ChevronTexaco, and Mobil. Most of them have been operating in Nigerian onshore region since the inception of the petroleum industry in Nigeria. Until the recent exit via divestment of some of the fields to indigenous companies, Shell, Chevron Texaco, and Agip dominated activities in the onshore region. IOCs operating in Nigeria are part of large multinational corporations with exploration, production, and in some cases, downstream operations all over the world. They are not parented in Nigeria. The parent companies are not Nigerian companies, but companies based in Europe or the United States. Most of these companies form subsidiaries in Nigeria through which they enter into production contracts with the Nigerian government as either joint venture (JV) partners, production sharing contractors, or in few cases, service contractors. While they may be altruistic, their main business objective is to make profit and provide financial returns for their global investors who are mainly in Europe and the United States. These companies, similar to any sound business outfit, will continue to do business in Nigeria as long as a dollar invested in Nigeria is relatively more profitable than a dollar invested elsewhere. When it ceases to be more profitable in Nigeria, they will activate an exit strategy and repatriate their resources to a more profitable location or back to their investors outside Nigeria. The exit strategy, as observed for most of the IOCs in other geriatric regions in the world, involves selling assets to some other investors and then figuratively returning to the parent company base with the proceeds. For example, BP Alaska sold some of its assets in North Slope to Hilcorp, a United States indigenous oil company in 2014 (Bradner, 2014). The fact that there is a chance of leaving behind liabilities and going back to the parent company location where the company is beyond reach or difficult to be reached and held accountable, is a potential high risk to the proximate stakeholders of the oil industry and sovereign governments, like the Nigerian government. According to Schaps & George (2017), a UK court has already ruled that Shell cannot be taken to court in the UK over pollution caused by its subsidiary in Nigeria. This makes decommissioning of these assets an important topic to evaluate at a time when the IOCs have not completely exited Nigeria.

Local Indigenous Operators (LOCs): The big indigenous oil producers include operating companies, such as Oando, Seplat, and Afren, and marginal field operators, such as Alteio, Excel Exploration, and Production. Indigenous operators began entering the scene in the late 1990s when Nigeria started implementing local content policy in the petroleum industry. Big companies such as Oando and Seplat, acquired fields from the IOCs or were awarded some mining leases by the government. Some of these companies are offshoots of business empires of a few individuals, a business arrangement that is typically vulnerable to key man risk. If the key promoters or owners for some reasons become disoriented, the companies will fail. A few of these companies have stood the test of time, expanded their investor base, and could be described as relatively low risk. However, there is another group of indigenous operators who are small companies with operations in marginal fields or a single field acquired from the IOCs. Most of them were hurriedly formed by indigenous businessmen as vehicles to access the petroleum rent. The business and organizational structures are infantile and business objectives are very short termed. This group, as estimated by Akpan (2017), produces approximately 240 Mbopd as at

2015. Acquisitions are becoming common and it is expected that there will be an increase in the percentage of assets under the indigenous/marginal portfolio as production from the fields decline and the IOCs continue to divest from Nigeria. From a decommissioning stand point, the focus is on whether they will be able to meet the decommissioning obligation, which will mature and become vested under their tenure. Financially, they are not as robust as the MOCs. Another concern is whether a contractual relationship exists between them and the original IOCs operators that could be leveraged to get the IOCs back to handle the decommissioning liabilities. All these will, to some extent, depend on the fiscal regimes, regulation, and policy direction in the petroleum industry in Nigeria which is currently nebulous. Setting up a good decommissioning policy direction may require the public to steer the government and its regulatory agencies in the desired direction. The public's response will be dependent on how aware and informed the public is about the imminence and problems of decommissioning of the fields.

National Oil Company (NOC): The NOC is the participating entity representing the federal government of Nigeria in the JV and business operations in the petroleum industry. Therefore, the final ownership right for equipment and infrastructures resides with the NOC, unless agreed or stated otherwise (Azaino, 2012; Stakeholder Democracy Network (SDN), 2015). Consequently, infrastructures could be left behind for continued utilization by the NOC or its new partners. Similarly, if they are not properly decommissioned, the responsibility will fall on the NOC. Given that the NOC is a government corporation, the final liability therefore rests with the Nigeria government, and ultimately the people and tax payers in general.

3.2.3. The Nigerian Government's Interaction with the Industry

The Nigerian government steers the petroleum industry toward its objective through a fiscal, regulatory, and legal policy framework. Leveraging this framework, the government interacts with the industry through the exercise of ownership rights over the natural resources and participation in business as an operator through its NOC and regulations. It seeks to maximize profit from the normal business operations through its participation in business operation using the NOC, NNPC, or its producing subsidiary, NPDC. Furthermore, it exercises its ownership rights by collecting royalties and other taxes according to the fiscal regime and policy which it exercises through NAPIMS, the investment arms of NNPC and other tax agencies. However, the government also interacts with the industry from an umpire perspective and also as a fiduciary for the citizenry by regulating the operations of the petroleum industry to the optimal benefits of the people of Nigeria. It uses the DPR, Federal Ministry of Environment, and relevant state regulatory agencies to achieve the regulatory, environmental, and exploitation accountabilities policy objectives.

3.3. Petroleum Fiscal Regimes and Arrangements in Nigeria

Petroleum fiscal regimes consist of legal and contractual arrangements that govern participation in the petroleum industry in a region. They set the types and manner of administration of taxes, royalties, profit sharing, and other financial benefits and liabilities resulting from exploitation of petroleum reserves. The fiscal policy elements are the most tangible and quantitative monetary means of evaluating the efficiency of government petroleum development and regulation policy framework, particularly the government take (GT) metric which encompasses royalties, bonuses, profit shares, and all forms of taxes. The fiscal regime and arrangements in Nigeria's petroleum industry (Figure 14) are mainly JV, PSC, service contract (SC), or marginal field concession (MFC).

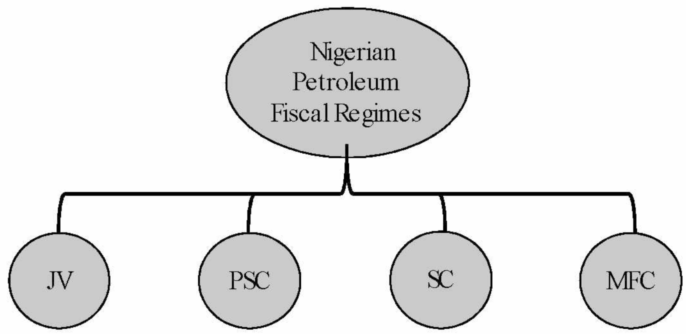


Figure 14: Petroleum fiscal regimes in Nigeria

Features of the JV arrangement include a partnership of one or more IOCs with the NOC, NNPC, at some agreed working interest ratio. Each partner is expected to contribute a working interest percentage of the total funding requirement for JV operations. The concession belongs to the NOC. The crude oil produced is shared in the same ratio as the working interest ratio. One of the partners is designated as the operator who manages the day to day affairs of the JV operations. In terms of fiscal tools, under the Petroleum Profit Tax Act of 2004, each partner in the JV is subjected to a profit tax of 65.75% for the first 5 years and 85% in subsequent years (KPMG, 2015; Oxford Business Group, 2016). There is room to modify this tax rate in the memorandum of understanding (MOU). An MOU is a document that spells out and governs how the partners relate. The JV model of concessionary fiscal agreement is no longer popular owing to several reasons amongst which is the inability of the NNPC to meet its funding obligations to the JV and associated operational inefficiencies. However, most of the onshore fields which are closer to their end of economic life are under JV arrangements.

The PSC came on board partly in response to the aforementioned challenges with the JV arrangement, the peculiarly difficult terrain, and huge cost of going into offshore deep-water operations. It was introduced in 1993 and has become the predominant fiscal operating model in Nigeria. Under the PSC arrangement, an IOC or indigenous operator is a contractor who takes on board all the risk and cost of exploration. The contractor can then recover its cost at a pre-determined percentage of the oil production, if the development is successful. After full cost recovery, the contractor will continue to participate in profit sharing, which could be paid either in crude oil or cash. On the other hand, if the development is not a success, the contractor solely suffers all the loss. The elements of the fiscal arrangement are similar to those in the JV model. However, the contractor will have a cap on the amount of cost oil that can be recovered in a year. The profit sharing arrangement may vary too. The petroleum profit tax is approximately 50% (Oxford Business Group, 2016).

The SC model is similar to the PSC model. The key difference is that while under the PSC, partners own the produced crude oil according to their working interest ratio, the contractor under the SC model has no right to the produced crude oil. The SC is paid by the government, either in kind or cash, for its services according to pre-agreed terms. Similar to the PSC, if the development is not successful, they lose their committed funds, solely bearing the risk. The contractor pays only a tax of 30% on their service fees under the Companies Income Tax Act. It does not pay a petroleum profit tax (PPT).

MFCs are mostly used to handle marginal fields awarded to indigenous operators. The Nigerian government introduced Marginal Field Operations Fiscal Regime Regulation in 2005 to help transfer fields that have been held dormant for approximately 10 years by IOCs to indigenous operators. The elements of the fiscal regime as it applies to marginal field concessions are more lenient and offer the benefit of a tax break.

Irrespective of the fiscal regime, the overall measure of financial benefits to the government from the industry is in terms of the GT, which comprises of royalties, and different taxes and profits (van Meurs, 2008). As such, from a government and hence citizenry benefit standpoint, the GT is an important measure and metric. In evaluating the dynamics of decommissioning policies and strategies, the impact on GT and its sub elements, such as taxes, royalties, and JV profit share, will therefore be significant measures or metrics to evaluate. This study will evaluate the impact of decommissioning liabilities on the respective revenue streams that constitute the GT.

3.4. Crude Oil Reserves and Growth Trend in Nigeria

Nigerian crude oil reserves were 37 billion barrels as at 2015. The reserves were approximately 21 million barrels in 1959, 17.9 billion barrels in 1992, and stood at approximately 37 billion barrels in the last few years (British Petroleum, 2016). A closer look at the profile in Figures 15 and 16 suggest that high year-on-year (YoY) reserve growth rates were observed in the first 2 decades of oil exploration in Nigeria. In some instances, it was as high as 200%. The last 2 decades saw a near 0% YoY growth in reserves. While unfavorable business and operational environment has been blamed for the low level of exploration activities and reserves addition, it may also be that the volumes of yet to be discovered crude oil resources are very few after over 50 years of exploration activities, particularly with the onshore fields. Most of the reserves added in 1990s–2000s were from offshore fields. The government is making efforts to boost exploration activities and reserves growth. If Nigeria is unable to increase its crude oil reserves which are being depleted at approximately 2.5% annually, then the reserves may be exhausted (i.e., reserve-to-production ratio, RtP) in 40 years at the current 2,500 Mbbl/day rate of production. Given a 4,000 Mbbl/day growth aspiration, this may be accelerated by 2 decades with an RtP of 25 years. This study will forecast crude oil production profile for Nigeria under plausible scenario and test the sustainability of Nigeria crude oil reserves with the risk of occurrence of decommissioning and abandonment within the next 2 to 4 decades, particularly in onshore fields. The YoY data shows that the reserves have not been growing significantly for the past 2 decades, which is a piece of information with significant concern for sustainability of crude oil production (Figures 15 and 17).

3.5. Crude Oil Production in Nigeria

Crude oil production in Nigeria rose from approximately less than 500 Mbbls/day in the early 1960s to approximately over 2,000 Mbbls/day in late 1970s as shown in Figure 17. The production profile does not indicate a steady rise which may be attributed to significant sociopolitical and economic factors. There was a characteristic significant decline in the early 1980s and another rise to a peak of approximately over 2,500 Mbbls/day in the early 2000s. Since 2010, there has been a decline of approximately 2.5% per year to a level below 2,500 Mbbls/day in 2015. While it is a fact that political unrest and inclement business environment have hampered production, it has been observed that exploration activities are currently low in the Nigeria onshore region (Campbell, 2013; Khan, 1994).

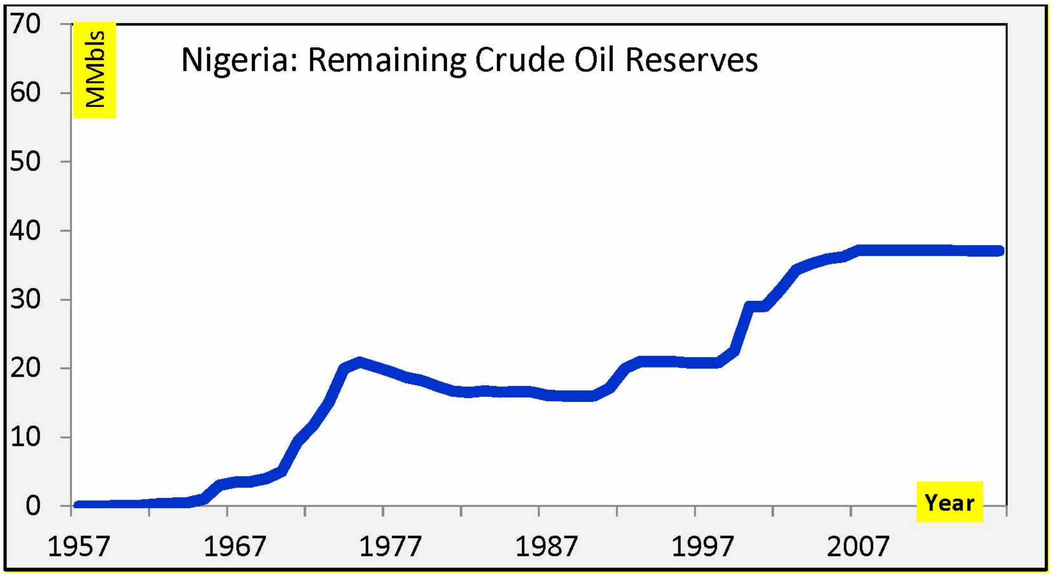


Figure 15: Profile of Nigerian remaining crude oil reserve at year end from 1957 to 2015

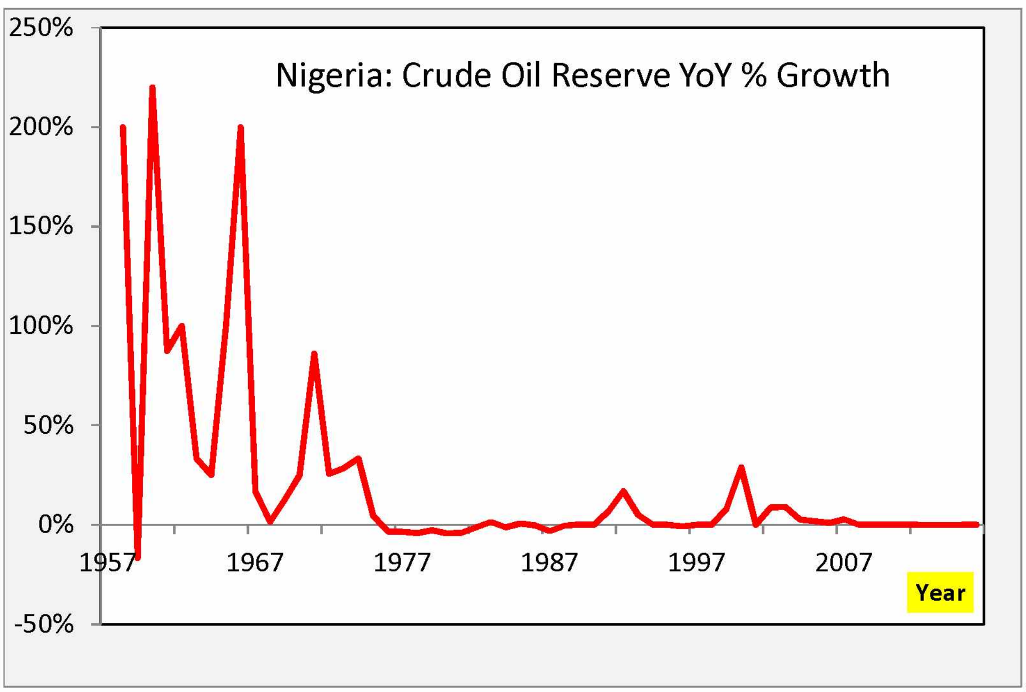


Figure 16: Year-on-Year (YoY) crude oil reserves growth in Nigeria

Another notable fact is that the current crude oil production popularly reported for Nigeria is a combined production from both offshore and onshore fields (Figures 17 and 18).

New field development projects have been on the increase in offshore locations since the early 1990s leading to increase in the share of crude oil production from offshore fields. However, production from individual fields has been on a faster decline (Campbell, 2013), which is typical of offshore fields due the high capital investment and desire of business entities to recover their investment as quick as possible. It is anticipated that the offshore fields will decline faster than the onshore fields that have been around for almost 60 years, even though additional new offshore fields are under development. Decommissioning and abandonment is not a too distant future problem for some of these offshore fields. However, for the purpose of this study, the focus is onshore fields.

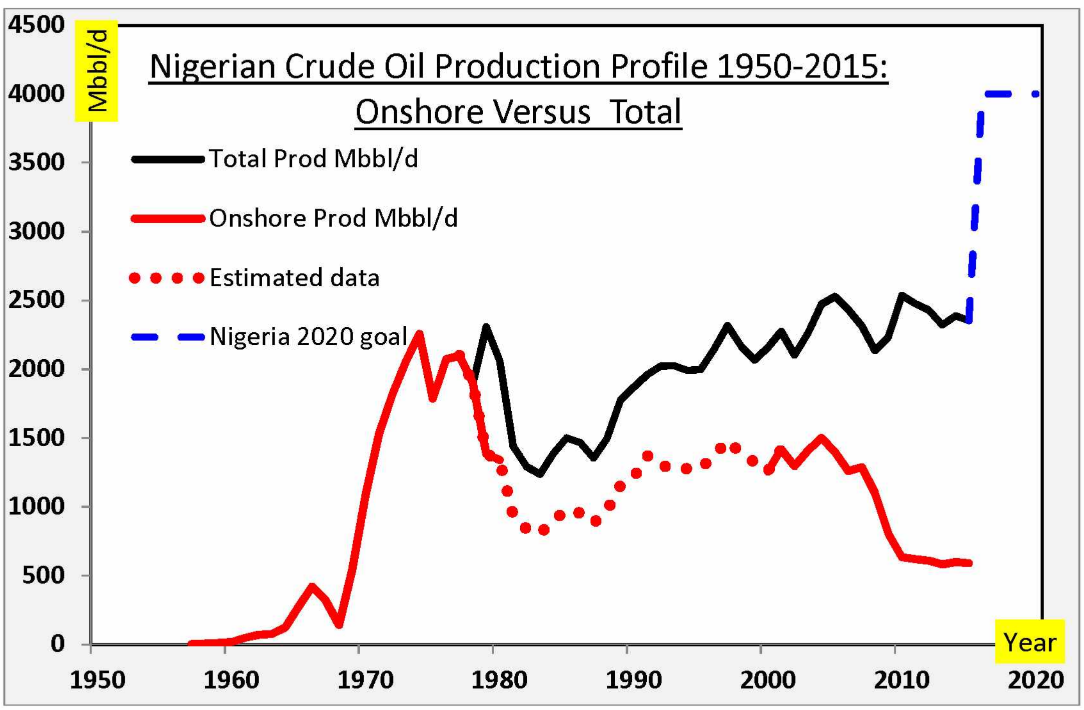
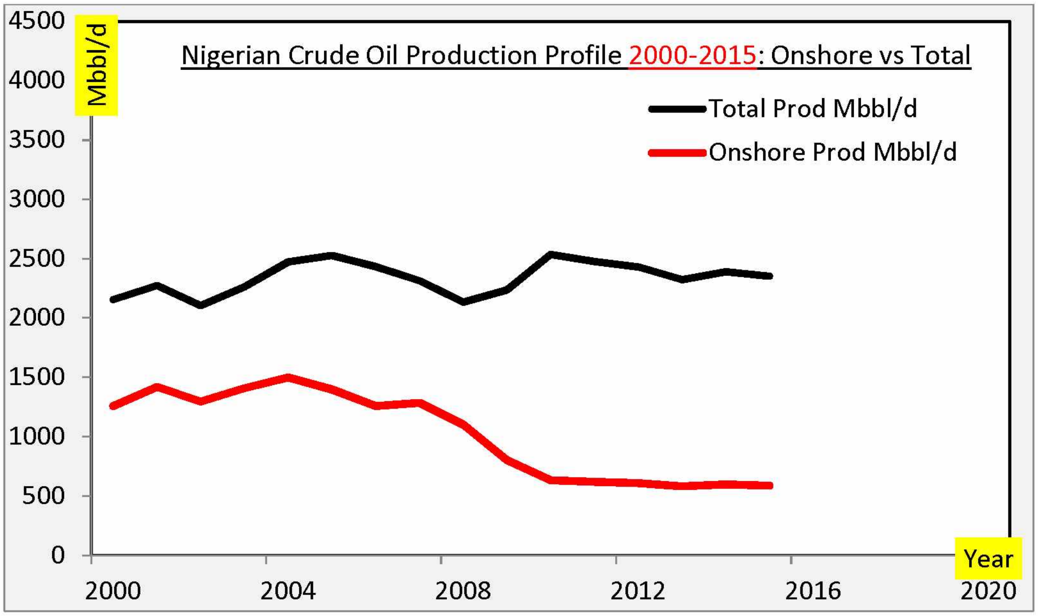


Figure 17: Crude oil production profile in Nigeria – Onshore fields and all fields combined

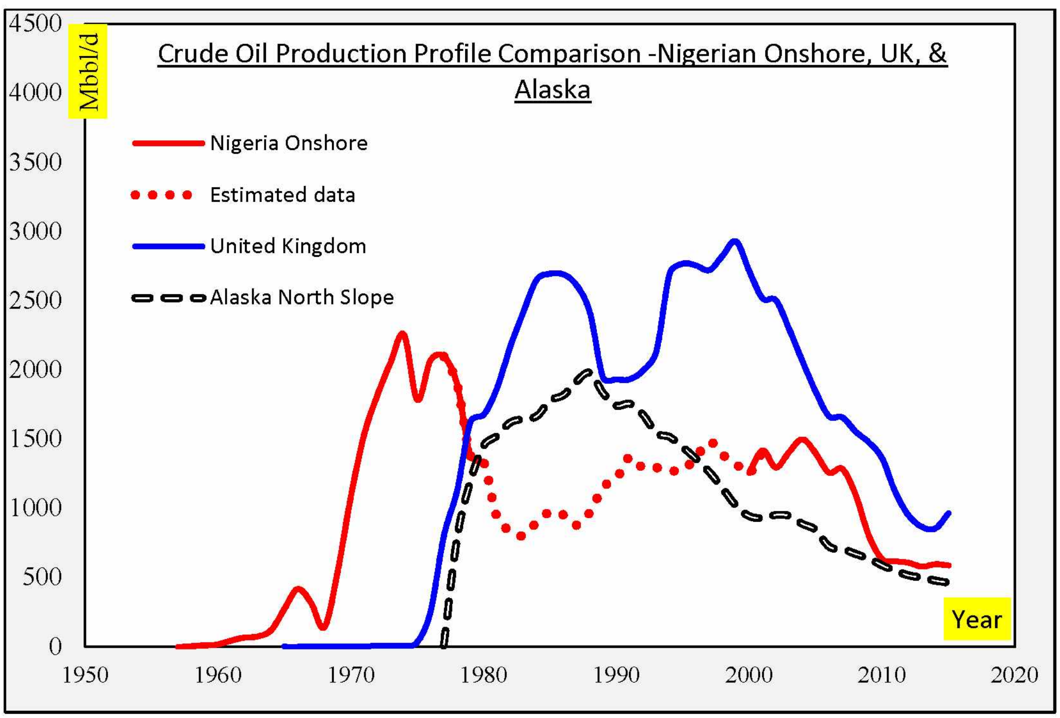
3.5.1. Onshore Crude Oil Production

The growth in production from offshore fields is making the decline in production from onshore fields less apparent (Figures 17 and 18). As observed by EcoBank (2013) and Stratfor (2013), crude oil production from onshore fields has dropped to less than 30% of the total crude oil production from Nigeria. In the early 1960s, approximately 100% of crude oil production in Nigeria was from onshore fields. Presently, a larger percentage of Nigeria's crude oil production comes from offshore fields, which are being looked upon for Nigeria's year 2020 production target of 4,000 Mbbl/day. The IOCs are exiting onshore fields and concentrating on offshore fields. This is partly owing to the fact that offshore operational environment seems to be far away from political unrest. However, it could also be due to the decline in crude oil production rate from onshore fields. Production decline driven by natural factors has set in for most of the onshore crude oil fields. For example, OML-30, which consists of eight major onshore fields, Afiesere, Eriemu, Evwreni, Kokori, Olomoro-Oleh, Oweh, Oroni, and Uzere fields have declined from 280 Mbopd at its peak in 1971 to 38 Mbopd in 2012 (Heritage Oil PLC, 2013). This pattern of decline and associated divestment activities have been observed in geriatric regions, such as UKCS and GOM as shown in Figure 19. Campbell (2013) concluded that the Nigerian onshore region can be described as a mature petroleum region.



Data from British Petroleum (2016) except onshore production inferred from EcoBank (2013).

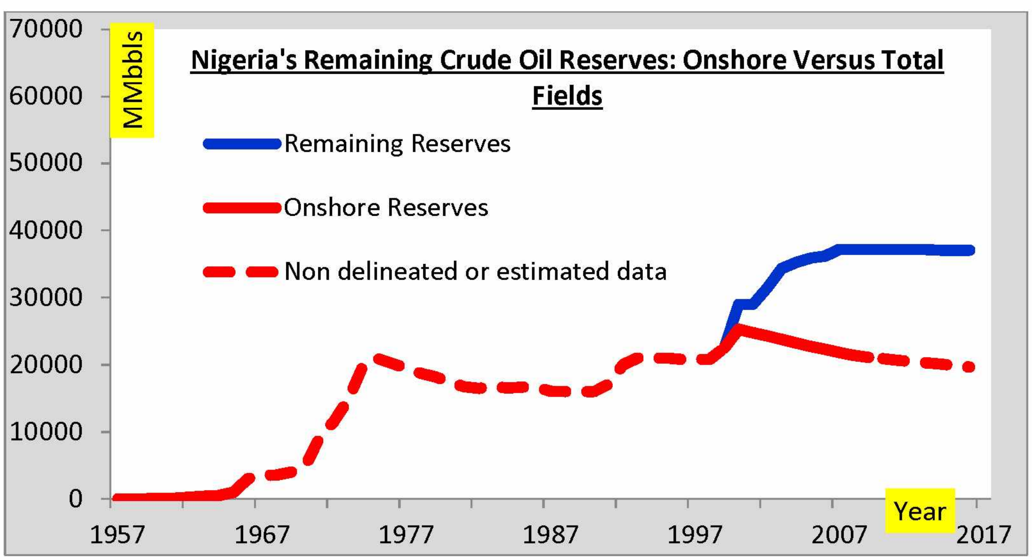
Figure 18: Focus on the years with decline in production – 2000-2015



Data from British Petroleum (2016) except onshore production data inferred from EcoBank (2013) and estimates based on inferred onshore fields' share of total production from various sources.

Figure 19: Declining crude oil production profile – Nigerian onshore versus UK and Alaska

Crude oil production from onshore field in Nigeria is currently at approximately 550 Mbbl/day (EcoBank, 2013), declining from approximately 2,000 Mbbl/day in the early 1970s. For onshore fields, barring any unexpected reserve growth scenario, at the current estimated production rate of 550 Mbbl/day, these fields will be ready for decommissioning and abandonment in a couple of decades (Figures 18, 19, and 20). As their productions decline, the interest in continuing business investment in these fields by stakeholders will also diminish. In addition, ownership/operatorship structures will change with the IOCs exiting and transferring ownership/operatorship to small local indigenous investors. Therefore, it is expedient to understand the associated risk with these changes and to reliably measure the readiness of existing fiscal and regulatory framework for their decommissioning and abandonment. There is no evaluation metric to measure the level of readiness for decommissioning or vulnerability to decommissioning default risk for Nigeria, in extant literature.

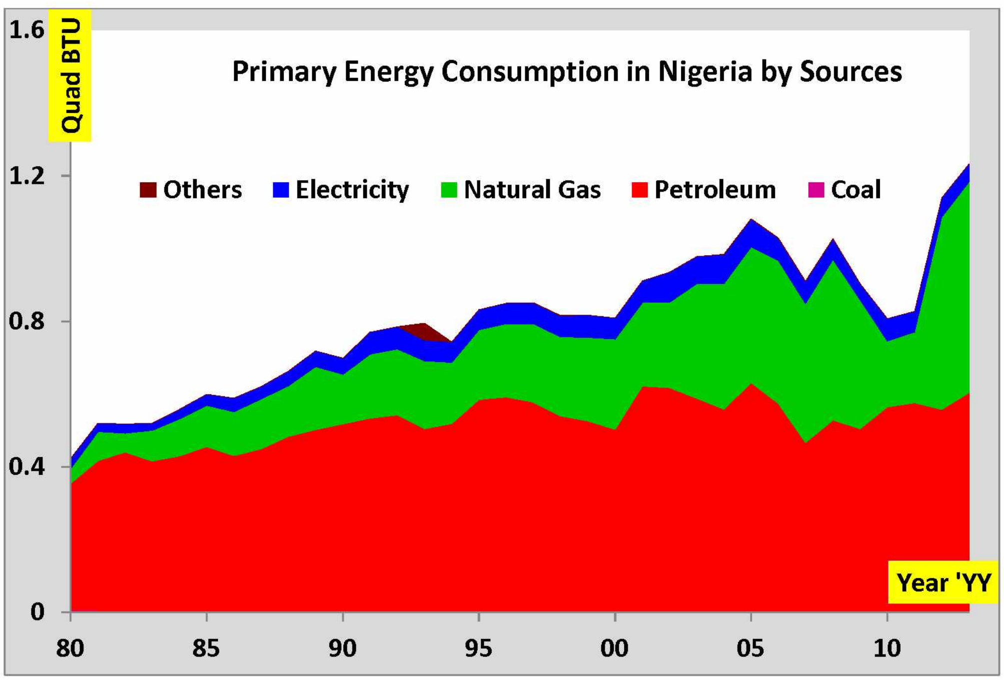


Data from British Petroleum (2016), except onshore reserve data for 2000 – 2009 inferred from EcoBank (2013) and 2010-2015 inferred from onshore fields' share of total reserves from various sources.

Figure 20: Remaining crude oil reserves – Nigerian onshore versus offshore fields

3.6. Domestic Crude Oil Consumption Patterns in Nigeria

Crude oil is the major source of primary energy in Nigeria as shown in Figure 21. There is an emerging trend of utilizing natural gas, which Nigeria has in abundance. However, this is very insignificant in comparison to gasoline and diesel which come from crude oil, and are used as fuel for vehicles, and private electric power generators for industries and homes. To meet the demand for diesel and gasoline, approximately 250 Mbbl/day of crude oil is consumed locally in Nigeria. In addition to crude oil being the main source of foreign exchange and significant contributor to revenue for the federal government, it is also needed at an increasing rate for supply of fuel for domestic consumption.



Data from United States Energy Information Administration (2016)

Figure 21: Primary energy consumption in Nigeria by sources.

As shown in Figures 21, 22, and 23, crude oil intensity of Nigeria is approximately 620 bopd/billion dollars of GDP (United States Energy Information Administration, 2016; World Bank, 2017). With anticipated GDP growth, more crude oil will be required for domestic consumption, which will trigger increase in production rate to meet both the increase in domestic demand and need for foreign exchange. It can be inferred that there is a credible near future scenario where Nigeria will need to increase its crude oil production rate over and above 2,500 Mbbl/day to cover for the increase in domestic consumption of crude oil and required foreign income. This may mean a faster rate of decline, quicker EOFL, and quicker occurrence of decommissioning, if there is no reserve addition. It will be more evident in the onshore fields that will provide crude oil supply to local refineries. The refineries are currently fed by pipeline network from only onshore fields. The offshore fields do not supply crude oil to the refineries.

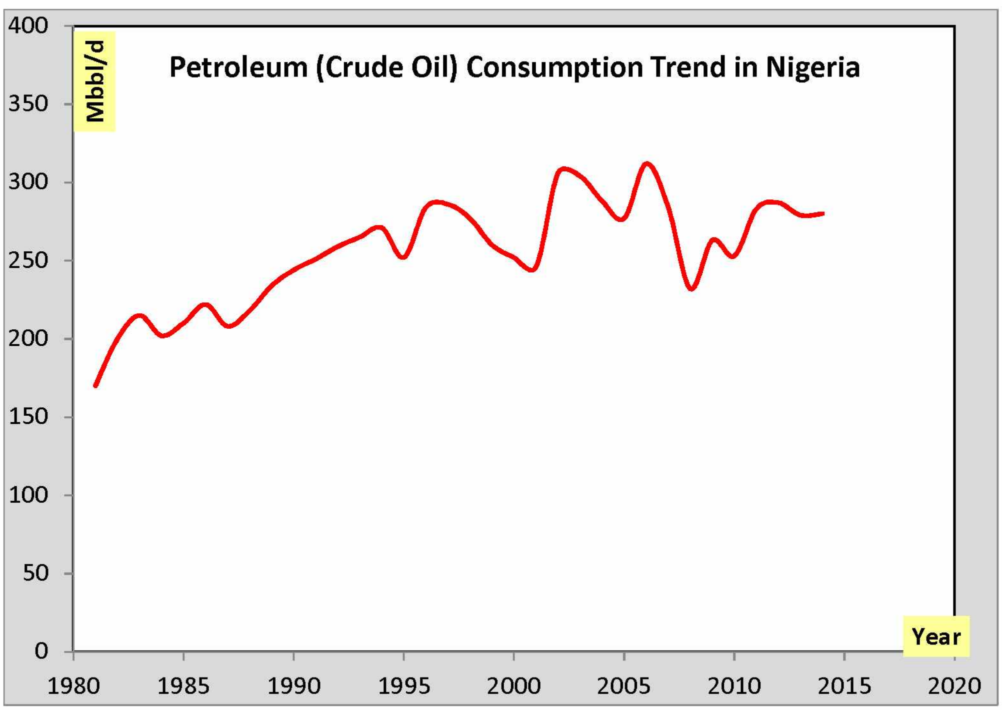


Figure 22: Petroleum consumption trend in Nigeria

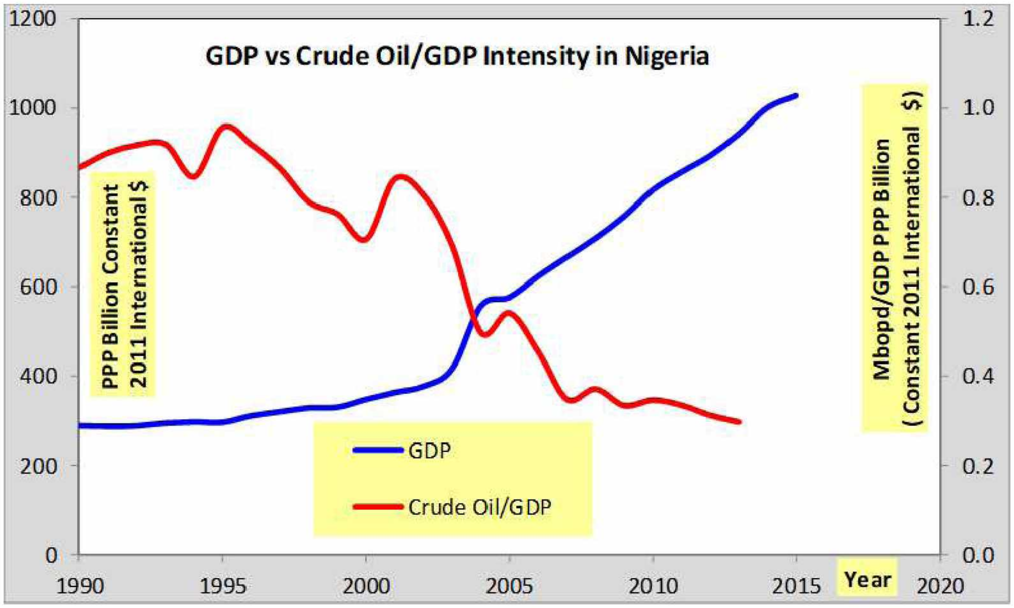


Figure 23: Crude oil energy use intensity for Nigeria

3.7. Population and Economic Growth Aspirations in Nigeria: Implications for Decommissioning of Onshore Fields

According to the National Population Commission (2017), Nigeria population was estimated to be approximately 182 million in 2017. The current growth rate is approximately 3.5%, which means a population of 210 million by the year 2021. Out of this population, 50% will be under 30 years, which may suggest that the total energy use may not diminish, even with a lower energy use intensity. Nigeria has a consistent high population and GDP growth rates as shown in Figure 24 (International Monetary Fund, 2016; World Bank, 2017).

According to the National Planning Commission (2009), the country also has an aspiration to grow economic activities and attain an annual 13.8% GDP growth through 2020. Considering the need for energy to drive this growth and an estimated energy use intensity of 600 bopd/$1 billion GDP, approximately 580 Mbopd of crude oil will be required to achieve this goal. There may be questions about the adequacy of crude oil to support the domestic and export demands. While their answers are not the focus of this study, it is apparent that the occurrence of such a scenario may lead to a faster rate of production and earlier decommissioning. It may also turn out that the future generation could be left with decommissioning liabilities, while the remaining crude oil production left for them is relatively lower or inadequate, which will be an intergenerational equity problem.

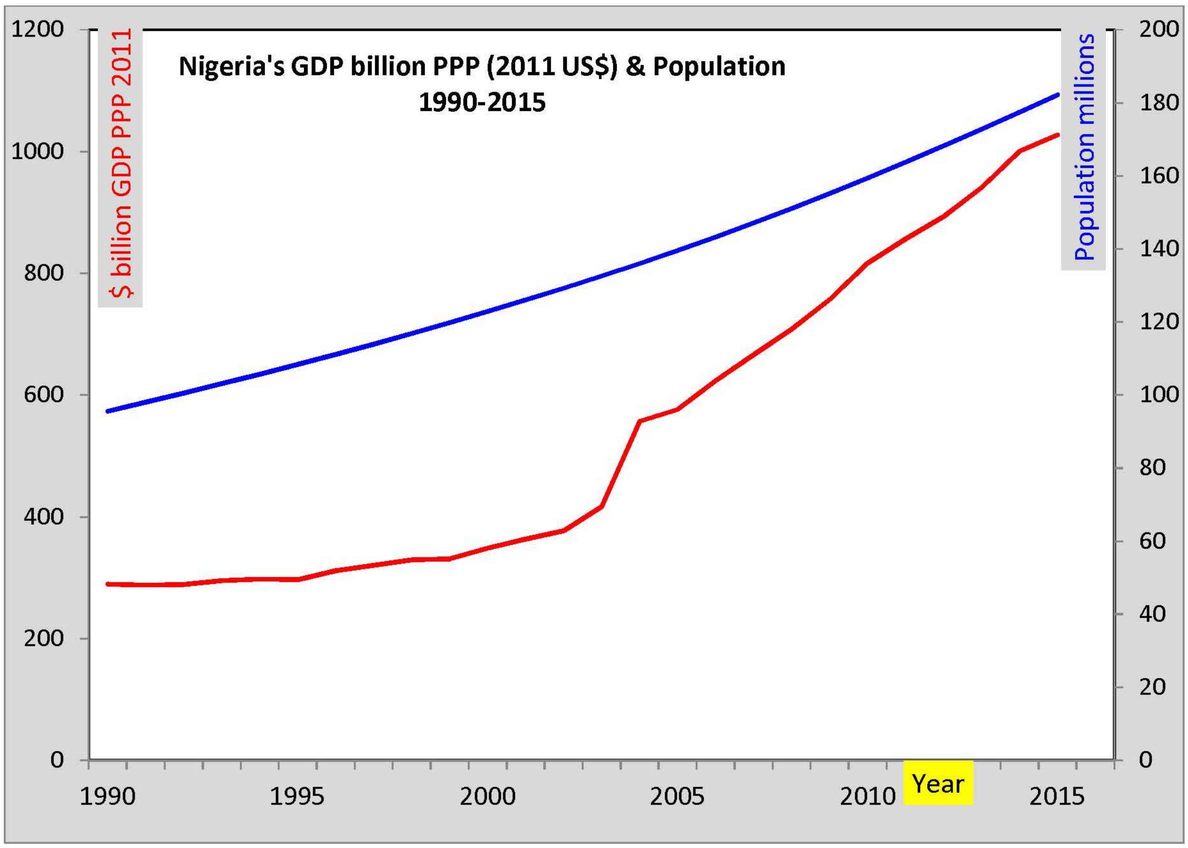


Figure 24: GDP and population trend for Nigeria

The future growth scenario supports the assumption that crude oil production may be on a significant irreversible decline, and decommissioning of onshore fields in Nigeria is no longer a far future event. It is expedient to begin to prepare for decommissioning now, if it is to be done in a sustainable manner with intergenerational equity. Sustainable decommissioning is the responsible way expected of nations and responsible corporate entities to go about development and subsequent decommissioning of natural resource exploration and exploitation facilities.

As the end of crude oil exploitation draws near for the fields, anxiety and concerns are expected from the public over the loss of benefits hitherto enjoyed from the resource and resulting liabilities from the abandoned facilities. For the public in Nigeria to care about this end of economic life scenario, they need to know and realize that production and revenue from the fields are dwindling toward cessation. Simultaneously, they need to be aware of decommissioning liabilities resulting from the abandoned facilities and associated cost to handle them safely. Currently, they do not appear to care about decommissioning and there is no outrage owing to the fact that most likely, they do not realize the impeding implication of the production decline and associated cost of decommissioning (Stakeholder Democracy Network, 2015). Due to huge information asymmetry in the industry, stakeholders are hindered from becoming aware of this imminent loss of revenue and the huge cost of liabilities involved, particularly in developing countries, such as Nigeria. One of the objectives of this study is to provide new methodologies that can overcome the challenges associated with information asymmetry in the petroleum industry, particularly in Nigeria.

3.8. Crude Oil Mineral Rights and Access to Information Bias in Nigeria

In natural resource management, access to information is closely related to legal rights of ownership and access to the natural resource, which in this case is the crude oil reserve in Nigeria's onshore fields. It is particularly challenging to gain information on petroleum revenue and cost in Nigeria owing to the political economy of petroleum in Nigeria (Khan, 1994) and the property rights regime that does not provide for private ownership of petroleum resources. Ownership rights to the crude oil resource are vested on only the federal government in Nigeria. The Nigerian constitution provides the federal government exclusive powers over "all matters relating to the regulations and management of the oil and gas industry" (Ekhator, 2016, p153). Akinjide-Balogun (2001) earlier corroborated this position and pointed to the provisions of the Petroleum Act, 1969, that "vested the entire ownership and control of petroleum" resources in Nigeria on the federal government. Crude oil is not an open resource that anybody can access or benefit from in Nigeria. It is a common pool resource with its ownership role vested on only the federal government. The federal government holds the access, withdrawal, management, exclusion, and alienation rights. The federal government delegates part of these rights—access, withdrawal, and management rights—to the oil companies with whom it operates a JV agreement for crude oil production. Being compromised as a business partner in the operations, the government lost an uncompromised position necessary to effectively enforce regulations through its agencies. Hence, for example, the government may not be able to demand adequate public information disclosure on the operations of the oil industry. Even the federal government does not have information beyond that provided by the oil companies to the regulatory agencies. Most information on activities of the petroleum industry are held by the IOCs and a few pieces of information by the federal government who is the only stakeholders with legal de jure rights to petroleum mineral resources in Nigeria (Table 3).

Table 3: Institutions and stakeholder groups, and bundle of rights to crude oil in onshore Nigeria

Agents / Type of rights	Access	Withdrawal	Management	Exclusion	Alienation	Roles
Private Citizens	No	No	No	No	No	Rent seeker
Non-Governmental Organizations (NGOs)	No	No	No	No	No	Rent seeker
Non-oil Producing State and Local Government and Communities	No	No	No	No	No	Rent seeker
Oil Producing State and Local Government	No	No	No	No	No	Rent seeker
Oil Producing Local Communities	No -but de facto rights	No	No	No but hold de facto rights	No but hold de facto rights	Rent seeker/ De facto Owner
Multinational Oil Companies (MOCs)	Yes (De jure)	Yes (De jure)	No	No	No	Authorized User
Indigenous Oil Companies	Yes (De jure)	Yes (De jure)	No	No	No	Authorized User
Government Agencies & Oil Company	Yes (De jure)	Yes (De jure)	Yes (De Jure; delegated from Federal Government)	No	No	Proprietor/ Claimant
Federal Government	Yes (De jure)	Yes (De jure)	Yes (delegated to government agencies)	Yes (De jure)	Yes (De jure)	Owner

Table 4: Institutions and stakeholder groups and bundle of rights to crude oil in the United States

Agents / Type of rights	Access	Withdrawal	Management	Exclusion	Alienation	Roles
Private Citizens participating as owners	Yes (De jure)	Yes (De jure)	Yes (De jure)	Yes (De jure)	Yes (De jure)	Owner
Non-Governmental Organizations (NGOs)	No	No	No	No	No	Rent seeker
Non-oil Producing State and Local Government and Communities	No	No	No	No	No	Rent seeker
Oil Producing State and Local Government	Yes (De jure)	Yes (De jure)	Yes (De jure)	Yes (De jure)	Yes (De jure)	Owner
Oil Producing Local Communities (via Native Corporations)	Yes (De jure)	Yes (De jure)	Yes (De jure)	Yes (De jure)	Yes (De jure)	Owner
Multinational Oil Companies (MOCs)	Yes (De jure)	Yes (De jure)	No	No	No	Authorized User
Indigenous Oil Companies	Yes (De jure)	Yes (De jure)	No	No	No	Authorized User
Government Agencies	No	No	Yes (De Jure; delegated from Federal Government)	No	No	Proprietor
Federal Government	Yes (De jure)	Yes (De jure)	Yes (delegated to government agencies)	Yes (De jure)	Yes (De jure)	Owner

Access to information on decommissioning is challenging for private stakeholders as the IOCs hold such information as confidential and proprietary to their business (Rogers & Atkins, 2015). In addition, gaining information from the government regulatory agencies is consistently difficult due to challenges with technical capacity, weak institutions, and compromised position where the government is a JV partner in the operations (Lawal, 2008). This sometimes makes it difficult for the regulatory agencies to effectively demand for these pieces of information from the operators and make them available to the public.

As noted earlier, crude oil in Nigeria is a common pool resource with mineral rights regime different from a combination of common pool resource and private mineral right regimes (Ostrom & Hess, 2010; Schlager & Ostrom, 1992) in places such as the United States. Tables 3 and 4 show the list of stakeholder groups and comparison of their mineral property rights between Nigeria and the United States. This mineral rights asymmetry that favors the federal government, its agencies, and the operating companies that are also JV partners to the federal government, also plays a role in the availability of information to stakeholders. Information asymmetry hinders awareness about decommissioning and does not incentivize public participation toward a sustainable decommissioning policy development goal.

Access to information on a natural resource is often closely related to the legal rights to the resources. Without legal rights, access to information may be constrained with difficult legal hurdles, even if there is a legislation that supports disclosure of information to the public. For example, in Nigeria, even with the 2011 Freedom of Information bill, the Lagos state government, one of the most progressive state government in Nigeria, has been leveraging the legal system to deny disclosure of government expenditure (Akeregha & Akhaine, 2017). Stakeholders are expected to interact over a public issue, such as decommissioning, and if all the stakeholders have equal access to information, they will eventually arrive at a net stakeholders' position that optimally favors all stakeholders. However, with information asymmetry, stakeholders with legal access to information, particularly on production and decommissioning related information, tend to hold back on these pieces of information as a sort of control and power dominance to bias the net stakeholder effect. It can be inferred that amongst other factors, this barrier to information supported by the nature of crude oil as a common pool resource and associated mineral right regime in Nigeria, hinders public participation which is necessary for a sustainable decommissioning policy development.

Nigerian public and government may be considering the occurrence of decommissioning to be far way in the future, effectively making themselves remote from the impact. However empirical observation from other countries, such as the UK, Malaysia, Thailand, the United States – Gulf of Mexico, Pennsylvania, and Texas, show that the end of field life and decommissioning is not a reality that is going to occur in the very far future. In addition, decommissioning and abandonment does not necessarily have to follow typical demand and supply economics curve or production decline curve. It could occur abruptly due to non-economic reasons such as the case of sociopolitical crises in Ogoni fields in Nigeria where Shell lost the social license to operate and have to abruptly plan for decommissioning (United Nations Environment Program (UNEP), 2011). It may be due to unanticipated economic factors. For example, a sudden and protracted low oil price driving a sudden exit from the fields. Effective stakeholder alignment is required in earnest if sustainable decommissioning is to be achieved

(Shell, n.d). This has been identified in the nuclear industry (Pescatore et al., 2007). The International Atomic Energy Agency (2009) noted that not only did “legal and moral imperatives encourage” early engagement of stakeholders on decommissioning activities, they also yield indispensable benefits.

3.9. Proposition for a Focus on Nigerian Onshore Crude Oil Fields

In summary, crude oil production from Nigerian onshore fields is on the decline and may even decline faster due to the need for more revenue and increase in domestic consumption to supply more energy needed to support population and economic growth. The fields are mature with limited exploration activities taking place. The facilities have also begun to experience the challenges of obsolescence. As a result, without new field development activities in the horizon to support their upgrade, they would soon become shut-in and abandoned.

There is a rise in the trend of IOCs exiting onshore fields and divesting their portfolio to indigenous companies. Financially, indigenous companies are not as robust as the IOCs, increasing the anxiety that they can abandon the decommissioning scope of work for the government and public to complete. Therefore, it is appropriate to commence discussion on decommissioning of the onshore fields before the complete exit of the IOCs, after which Nigeria will be left without any party to hold responsible for the decommissioning of these fields. The fields will then become orphan fields.

Nigerians should neither live in ignorance of the imminence of these liabilities nor ignore participation in policy development for decommissioning of the onshore crude oil fields. They need to push for policy objectives that will deliver on sustainable management of these liabilities. To encourage effective public participation, data and information on triggers and effects of the decommissioning process, such as production decline, anticipated EOFL, environmental standards for decommissioning and cost of decommissioning liabilities, and imminence and vulnerability to decommissioning default risk, should be easily accessible and interpretative. The current decommissioning discussions are too exclusive to the oil companies to adequately support sustainable decommissioning policy development in Nigeria.

Therefore, one of the sub-objectives of a sustainable decommissioning framework is the availability and access to these requisite pieces of information. However, within the institutional and mineral rights frameworks, this will be challenging to accomplish in Nigeria. Changes to the frameworks are not easily attainable within the Nigerian political system. As an alternative, there needs to be a methodology to explore publicly available data to develop some credible indicators on cost and vulnerability to decommissioning liabilities for onshore fields in Nigeria.

4. Decommissioning Liabilities – Scope Inventory and Cost Estimating Challenges

Cost estimating is the process of determining the approximate size of monetary resources needed to complete a project, in this case, decommissioning of onshore fields in Nigeria (Project Management Institute, 2013). Every cost estimate requires some form of scope definition as a basis for the estimate. A fundamental factor in the evaluation of decommissioning liabilities is the definition of the standard to which the entity or country will prefer the location to be restored. Rothe (2005), in the evaluation of DR&R responsibility for petroleum fields in Cook Inlet Alaska, concluded that the "cost of DR&R [ ] is hard to estimate without knowing what standard for DR&R will be set by ADNR [Alaska Department of Natural Resources]," which is the government regulatory body with oversight responsibilities for decommissioning in Alaska.

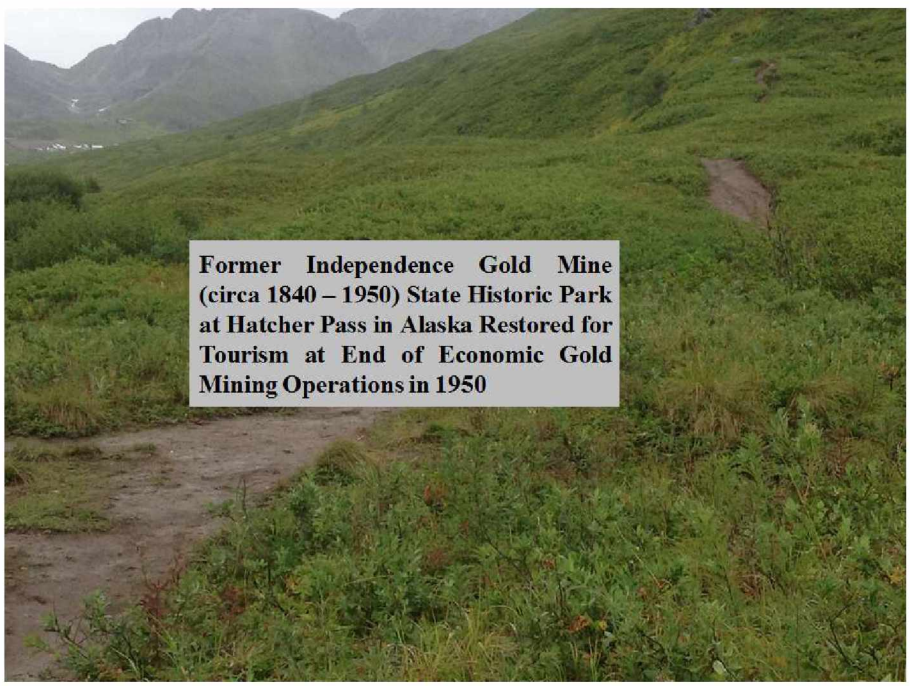


Figure 25: Scenic view of former Independence gold mine site Hatcher Pass, Alaska

Dondo (2014) also observed that the legally required standard for reclamation is one of the key questions facing cost estimations for mine closures, which is also related to decommissioning of petroleum fields. For example, if an oil field location will be used for historical tourism purposes at the end of its economic life, there will be no need to remove all the facilities. The pre-1900 gold mine tourism site located at Hatcher Pass Alaska (Figure 25) is a good example of how a natural resource facility may be used for tourism at the end of the economic production from the facility. If on the other hand, it is to be restored for agricultural use, then, in addition to the removal of facilities, restoration of the soil for arable purposes is required.

4.1. Liabilities: Defining Scope and Estimating Cost of Decommissioning

In the second chapter, a high-level definition of scope of decommissioning and abandonment activities was highlighted. Depending on the phase in the petroleum development life cycle, the level of definition of a decommissioning scope and plan may be low or high. However, the level of scope definition neither prevents cost estimation nor offers an excuse for not having a cost estimate for the decommissioning phase at any time during the life cycle of a petroleum field. The level of accuracy of cost estimates are acceptably expected to vary with the level of scope definition (Snyder, 2013). Morton et al. (2011) recognized the importance of assumptions in the cost estimating process and noted that in the early life of a facility, assumptions may be "relatively broad and far reaching," but will become focused as the execution time draws near.

Therefore, at any stage of the petroleum field development cycle, there can be an appropriate cost estimate for anticipated decommissioning liabilities of the field. It is a widely held position that cost estimates should be updated periodically to reflect any change in regulatory requirements, assumptions, or current perspectives. As decommissioning will be executed in the future, changes to regulatory requirements and scope should be anticipated, and the best practices require those changes to be recorded in the updated basis of estimate document. Considering challenges with estimating cost of decommissioning liabilities, Kaiser & Pulsipher (2008), and Talberth & Branosky (2013) also noted that ambiguous and unstable regulatory requirements, diversities in infrastructure configuration, and peculiarities with locations are some of the key sources of uncertainties to DR&R cost estimates. Byrd et al. (2014) added lack of information on completed decommissioning projects that can be used for historical benchmarking purpose as another challenge with estimating cost of decommissioning projects. Kaiser (2015b); Kaiser & Liu (2015), and Kaiser & Pulsipher (2008) adduced to the fact that cost data in general and for decommissioning in particular, are held as propriety information by operators in the industry for business advantages. Rothe (2005) also observed that the confidentiality nature of DR&R cost makes it challenging to gain access to data for any independent review. Decommissioning in the petroleum industry is still at its early stage and DR&R data are held confidential by most oil and gas companies. Therefore, preparation and gaining an understanding of cost estimates for decommissioning activities is challenging due to scope ambiguity, remoteness of execution time, multi-dependent variables that influence the cost estimate, ambiguous regulation, proprietary nature of cost data, and lack of experience in the industry (Figure 26).

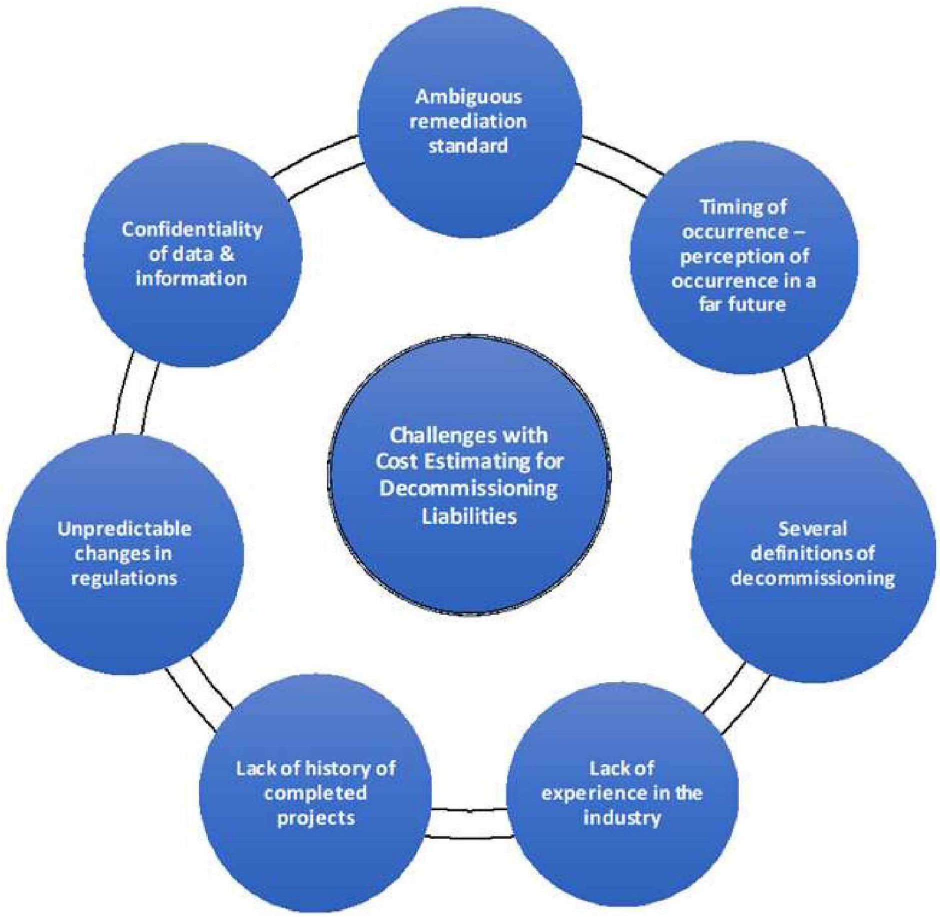


Figure 26: Challenges with cost estimating for decommissioning liabilities

These challenges notwithstanding, the need for a diligent cost estimate for decommissioning activities are critical. The lack of good cost estimate for decommissioning could lead to a huge public liability. Ho et al. (2016) observed that the actual average cost of well abandonment is higher than the average value of well abandonment bond demanded by the government in 10 out of 12 states that were surveyed in the United States. The United States government has been facing challenges funding the proper decommissioning of legacy wells in the National Petroleum Reserve–Alaska with over $90 million spent between 2002–2015 to properly abandon only 18 wells (Bureau of Land Management, 2017) out of the 90 wells earlier estimated in 2000 by BLM to cost $1.7 million (MWH, 2003). The actual money spent for less than 50% of the total number of wells, is already more than 5000% of the total initial cost estimate for all 90 wells. Yet, according to Bailey (2017), there are still arguments between the Alaska Oil and Gas Commission (AOGCC) and a prospective operator over the accurate cost of plugging the wells in Nicolai Gas field, with AOGCC estimating a million dollar per well in comparison to the operators estimate of $100,000 to $250,000 per well. By now, one could expect this gap in cost estimate to be narrower. Reliable cost estimates for decommissioning liabilities need not be challenging for the regulatory agencies and the public they represent, either to collate or calculate, as the public and government could end up paying for the liabilities.

4.2. Classes and Approaches to Cost Estimating for Decommissioning Liabilities

The cost engineering and estimating discipline, in recognizing the dynamic scenarios associated with cost estimating and challenges of scope definition, attempted to provide scalability to cost estimating efforts (Figure 27). The Association for the Advancement of Cost Engineering (AACE) developed a cost estimate classifications system that has five classes of cost estimates corresponding to different levels of scope definitions. Class 5, concept screening cost estimate, has the least level of scope definition, which is 0%–2%. It is accomplished through stochastic techniques, which are mainly parametric and analogous techniques. Expert judgment and generic trend analysis are also significant parts of cost estimating in this level. This cost estimate class will be applicable to decommissioning liabilities in the early field development phase or early planning phase for brown fields without a decommissioning plan. Similarly, for a region, nation, or corporate body, this could also be the basis for estimating the cost of decommissioning liability, if that has not been done before or established as an element of a good policy framework, similar to the onshore region in Nigeria. Class 4, study or feasibility cost estimate, goes with a 1% to 15% level of scope definition and makes use of parametric cost estimating techniques. However, reviews will be more than would be required for class 5 estimate. Class 3, preliminary budget authorization cost estimate, is used for a scope definition with about 10% to 40% level of completion. Even though parametric techniques could also be applied, the preference is to obtain unit cost or activity based cost estimates. Class 2 cost estimates require a 30% to 70% level of scope definition. The same techniques used in class 3 are used, but with more critique and application of learning curves, benchmarking, and current updates. If the scope definition is near 100%, then a class 1 cost estimate or bid/tender cost estimate is appropriate. Estimates at this level can be based on detailed designs, drawings, and price quote from submitted bids.

The Canadian Treasury Board classification system for cost estimates also has classes which are similar to the AACE classification, except that it has four classes instead of five classes, with class D relatively close to class 5 of AACE. AACE classes 3 and 4 relatively match the Canadian treasury board's class C. Its classes B and A match AACE classes 2 and 1, respectively. Morton et al. (2011) noted that all-in decommissioning cost estimates can be presented as unit cost in $ per ton using class 5 or D techniques. There are several other cost estimate classification systems, such as the Association of Cost Engineers (UK) classification with four classes – Order of magnitude estimate class-IV with -30/+30% accuracy; Study estimate class-III with -20/+20% accuracy; Budget estimate class-II with -10/+10% accuracy, and Definitive estimate class-I with -5%/+5% accuracy. The American National Standard Institute (ANSI) has a three-class system with order of magnitude estimate at -30/+50% accuracy; Budget estimate at -15/+30% accuracy, and Definitive estimate at -5%/+15%

accuracy. In the nuclear industry with mature decommissioning experiences, Organization for Economic Co-operation and Development (2016) also observed that differences exist in cost estimates for decommissioning activities from different estimating bodies due to variations in assumptions and methodology of cost estimating. Organization for Economic Co-operation and Development (2016) proposed "the adoption of a more homogeneous" methodology for estimating cost of decommissioning in the nuclear industry as a way to gain reliable cost estimates.

<table>
<tr><th>Standard / Class</th><th>Association for Advancement of Cost Engineering (AACE)</th><th>Canadian Treasury Board and Canadian Construction Association (CCA)</th><th>Association of Cost Engineers (UK) (ACostE)</th><th>American National Standard Institute (ANSI)</th></tr>
<tr><td rowspan="4">High scope definition and accuracy</td><td>Class 1 for bid tender/check estimate – (near 100% level of scope definition)</td><td>Class A –pre tender estimate with +/-10% accuracy. It is based on 100% scope definition and complete tender documents</td><td>Class I –definitive estimate with -5%/+5% accuracy</td><td>Definitive estimate with -5%/+15% accuracy</td></tr>
<tr><td>Class 2 for control/bid tender – (30% -70% level of scope definition)</td><td>Class B –substantive estimate used for effective project approval. It is based on 66% design and scope definition. Accuracy not stated</td><td rowspan="2">Class II –budget estimate with -10%/+10% accuracy</td><td rowspan="3">Budget estimate with -15%/+30% accuracy</td></tr>
<tr><td>Class 3 for budget authorization – (10% -40% level of scope definition)</td><td rowspan="2">Class C –design phase cost estimate with accuracy of +/- 25%. It is based on 33% design and scope definition</td></tr>
<tr><td>Class 4 for feasibility studies –(1% -15% level of scope definition)</td><td>Class III –study estimate with -20%/+20% accuracy</td></tr>
<tr><td>Low scope definition and accuracy</td><td>Class 5 for concept screening – (0%-2% level of scope definition)</td><td>Class D-Indicative estimate with accuracy of +/-30% for budget planning purposes and preliminary project approval. It is based on concept sketch design and less than 33% scope definition.</td><td>Class IV-Order of magnitude with -30/+30% accuracy</td><td>Order of magnitude estimate with -30%/+50% accuracy</td></tr>
</table>

Figure 27: Cost estimate classifications from different cost estimating bodies

4.2.1. The Environmental Custodian and Regulatory Agencies Perspective

While the professional cost estimating bodies focus on the level of scope definition and correlated accuracy of cost estimate, organizations with responsibility and accountability for decommissioning liabilities, such as the United States Environmental Protection Agency EPA and the British Columbia Oil and Gas Commission (BCOGC), emphasize on ensuring that no scope element is missed or omitted. Considering that decommissioning and abandonment liabilities may be classified as externalities and environmental liabilities of the crude oil production systems, the role of the regulatory agencies can be understood. British Columbia Oil and Gas Commission (2016) has a detailed systematic, but simple approach for the preparation of cost estimate for decommissioning liabilities outlined under its liability management rating program (LMRP). The agency's approach is similar to a work breakdown structure (WBS) with attendant cost breakdown structure (CBS) as recommended by Project Management Institute (2013). Under the LMRP, the scope of work for decommissioning is standardized into sub-categories such as well abandonment, well reclamation, facilities abandonment, and soil reclamation. These sub-categories are similar to a level 1 WBS. To help account for variances, scope factors associated with a wide range of standardized location categories, depths of wells, and types of well completions were also developed by BCOGC, similar to having a lower CBS level. The agency recognized that the scope requirement will vary across locations. As such, it defined a large range of input data to capture the potential variances. It used these wide ranges of scope factors to define standardized sub-elements, categories, or lower WBS and CBS levels, which helps to capture these variations to the extent that the mechanics and details are not distracting to the overall cost estimating objective.

Similarly, Kaiser & Pulsipher (2008) listed the sub-categories for offshore fields decommissioning as project management and engineering, plugging and abandonment, structure preparation, pipeline abandonment, conductor removal, structure removal, site clearance, and verification and miscellaneous. Byrd et al. (2014) also broke the scope into project scope sub-elements, such as planning, inspection and permits (regulatory compliance), well plug and abandonment (P&A), platform preparation, pipeline abandonment, conductor removal, topside removal and disposal, substructure removal and disposal, and site clearance and remediation. Zawawi et al. (2015) supported this standardization approach by acknowledging that even for offshore fields decommissioning, where each platform is a unique and complex design, when it comes to decommissioning, the major features are similar, except for weight and size. Therefore, it is tenable and adequate to apply factors to cater for such proportional variations in a WBS/CBS cost model, particularly if it is updated regularly. For example, with respect to the case study, Nigerian onshore crude oil fields, the scope of work for the decommissioning of a gathering facility or flowstation can be regarded as the standard unit of scope of work for decommissioning of the onshore fields. A factor can be applied to the cost estimate to account for various specific characteristics applicable to different locations or sizes.

Another aspect of ensuring that no liability is omitted is the application/adoption of appropriate cost estimating techniques. The United States Environmental Protection Agency (1996) identified seven methods of quantifying environmental liabilities. They are (i) actuarial techniques, which use statistical analysis of historical data on cost, occurrence of environmental liabilities, and effects to estimate environmental liabilities; (ii) professional judgment, which relies on expert judgments and assessment of liabilities; (iii) engineering cost estimation, which involves some estimation of the scope and activities, corresponding resource requirements, and cost with contingency factors; (iv) decision analysis techniques, which use tools such as decision event trees and probability distribution to characterize and quantify liabilities; (v) modeling, which tries to use historical data and relationship with cost to estimate environmental liabilities; (vi) scenario planning, which lays emphasis on probable future occurrences, and (vii) valuation methods, which involve legal and economic techniques of finding monetary value for the consequences of improper handling of environmental liabilities (Bailey, 1996). However, the United States EPA noted that modeling techniques supplement expert judgments in cost estimations. Kaiser & Pulsipher (2008), in their work for the United States Mineral Management Services (MMS), identified ways of estimating cost of decommissioning activities for offshore fields to include statistical relations, historical data, operator survey, activity breakdown, scaling rules, stochastic models, and engineering models. Zawawi et al. (2015) developed a logarithm transformation model for estimating decommissioning cost for offshore platforms in Malaysia. They adopted a simple regression analysis to a linear logarithmic function of multi-variable relationships and used it to establish the overall project cost. Similarly, though like a progenitor, the United States MMS had earlier adopted a regression cost model to capture several dependent variables in the cost estimation process for decommissioning of platforms located in the United States coast (Zawawi et al., 2015). MMS revise and update the cost estimate every 5 years. Even though it was for the development phase of a wind energy project, Kaiser & Snyder (2012) used a reference class approach that takes data of completed offshore wind farm projects from Europe to estimate cost for execution of similar projects in the United States.

Several cost estimating techniques have been developed. However, common to most of the techniques is the adoption of some form of modeling and analogy that utilizes historical data as input to provide a result that is a cost estimate for decommissioning liabilities. The results may not always yield precise estimates, but they can still serve as useful input data for cost planning and cost estimating in initial phase of projects. Therefore, the purpose of the cost estimate to the regulatory agency is very important to the choice of cost estimating method and technique (Funk, 1999). Giovannini (2014), in evaluating decommissioning cost assessment in the Italian and Swedish wind farm industry, added a focus on the important role of regulatory agencies in defining the scope and unit rate for decommissioning, and concluded that a type of top-down method based on explicit and consistent unit rates and scope set by the regulatory agency "…is very accurate and thorough." Dondo (2014) also supported this new point and argued that cost estimating for mine closure, which could be related to decommissioning of petroleum infrastructures, is "riddled with questions and tensions that need to be addressed by regulatory authorities." Essentially, public trust is on regulatory agencies to protect public's interest. A regulatory agency is tasked with the implementation of preventive and mitigation measures against the risk of the release of environmental liabilities from decommissioning and post-decommissioning phase. One of the ways regulatory agencies achieve their objectives is by setting bond requirements or asking for down payment and other forms of collateral. The purpose and selected preventive and mitigation measures also drive the cost estimating approach adopted by the agency.

4.2.2. Purpose Driven Cost Estimation for Decommissioning Liabilities

Kaiser & Pulsipher (2008), in another direction, posited that setting bond amounts to cover decommissioning liabilities do not require high level precision of decommissioning cost estimates as a bonding formula only needs to capture the average conditions and expected outcomes under normal future conditions. Instead, McGuigan (2000) called out the need for any cost estimate for decommissioning to capture transaction and cost factors that cover the scenario where government is the executor of the decommissioning project. This is important in the event that an operator fails to properly decommission a facility and the government has to call the bond for funds to execute the work using a government procurement procedure and price terms. Kaiser (2015b) called out a more elaborate focus that changed from just cost for removal of the facilities to encompass all associated decommissioning liabilities, terms, and conditions described as asset retirement obligations (ARO).

4.3. Asset Retirement Obligations (ARO) in Annual Financial Reports

The legal and compulsory responsibilities associated with decommissioning liabilities are better presented when described from an ARO perspective. According to Kaiser (2015b), "AROs are those [assets] for which there is legal obligation to settle under existing or enacted law, statute, written, or oral contract," even though their actual execution may be in the future. This brings into play the time value of money. The cost of ARO declared in financial reports is the present value of the estimated future cost of meeting all ARO associated with assets owned by an entity in a particular period. The dimension can also go beyond a time period to location, covering all ARO for assets located in defined areas, such as the Nigerian onshore region. Therefore, if any asset is properly decommissioned, the total cost of ARO for the entity or company is reduced by the amount of ARO cost particularly associated with that decommissioned asset. If any asset is acquired with associated ARO, these new liabilities are added to the company's existing cost of ARO. Therefore, appropriate and transparent accounting for the cost of ARO is required to track these changes.

Most national accounting standard bodies, securities, and exchange commissions, and international best practice expect companies to report their asset retirement or decommissioning obligations at fair value in the year that they were incurred. For example, Nigeria adopted the International Financial Reporting Standard (IFRS) in 2012. As noted by Bala (2013), "IFRS provides that, the present value of the costs of dismantling, removing, or restoring an oil and gas field as a result of a legal or constructive obligation is recognized as a liability and the corresponding cost capitalized as part of the related property, plant, or equipment." Similar to other countries where similar standards operate, oil and gas companies in Nigeria are required to recognize and disclose their decommissioning liabilities. ARO cost for the current period is reported in four categories: liabilities incurred during the current period (LI_t); liabilities settled (LS_t); accretion expenses (LA_t), and any revision in the estimated value of ARO liability (LR_t). The definition of these categories can be subjective; hence, the need for independent verification. Liabilities incurred (LI_t) covers additional ARO from newly drilled wells, installed or acquired assets, and working interests. The present value of cost to decommissioning these additional assets is captured in financial reports as liabilities incurred during the current period. Liabilities settled (LS_t) are portions of ARO reported at the beginning of the period that were settled during the current period. They may be AROs transferred to another operator along with a divested asset or a completed decommissioning activity, such as plugging and abandoning a well and site restoration. Accretion expenses (LA_t) are interest expenses calculated by multiplying the ARO reported at the beginning of the period by the company's credit adjusted risk-free rate (Kaiser, 2015a; 2015b). Accretion expense for the current period is added to the ARO reported at the beginning of each period, such that eventually, the ARO reported will be equal to the future cost of decommissioning at EOFL. Revision (LR_t) in estimated value captures changes to ARO value due to changes in any set of assumptions, such as interest rate and discount rate, made during the period. They may lead to an increase or decrease in the value of ARO. Hence, ARO at the end of the period is the sum of these four categories and the ARO reported at the beginning of the current period (Figure 28).

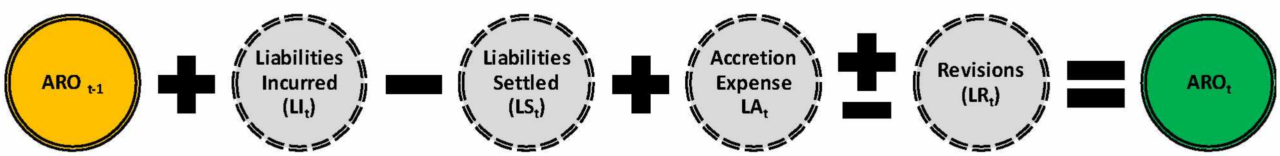


Figure 28: ARO categories and determination of ARO for the current period "t"

The ARO reported at the beginning of the period is the present value of the future cost of decommissioning at EOFL. These definitions and procedures used for the determination of ARO are based on Statement of Financial Accounting Standards (FAS) 143 or Accounting Standard Code (ASC) 410–20, and International Accounting Standards (IAS) 37. As outlined by Ernst & Young LLP (2016), McEown (2017), and Reeser (1984), the fair market value of ARO declared in a company's financial report is determined from the company's cost estimate to meet ARO in today's business environment and today's dollars. The cost estimate in today's dollar is converted through the application of an inflation rate or factor to the nominal cost of decommissioning at the EOFL. This future cost is discounted back to the current year using the company's discount rate to arrive at the present value of ARO for the company. The present value of ARO is added to the asset carrying cost and depreciated according to the company's adopted asset depreciation method.

As acknowledged and described by Bala (2013), Rogers & Atkins (2015), and McEown (2017), this method of estimating the reported value of ARO, as illustrated in Figure 29, is commonly adopted in the industry. The information and levels of disclosure provided for the discount rate, inflation rate, and completeness of the initial cost estimate, will affect the usefulness of the declared cost of ARO in the financial reports to the public. The question then arises whether the ARO cost estimate matches the definition of ARO from the regulatory body's perspective. Hence, McEown (2017) emphasizes the need for an independent third-party validation for ARO cost estimates. Most accounting standards require some form of third party audit of publicly declared financial information. These publicly declared costs of ARO are supposedly validated by independent financial and management audit firms. In the absence of better alternative, stakeholders who do not have so much information on decommissioning status of the field, similar to the oil companies, could have some comfort in adopting ARO cost from publicly declared financial reports at an aggregate level as a near accurate reflection of the cost of decommissioning liabilities. They can be used as a take-off point toward getting a baseline cost estimate for decommissioning liabilities, which will be sufficiently good for the purpose of engagement and policy discussion between operators and stakeholders.

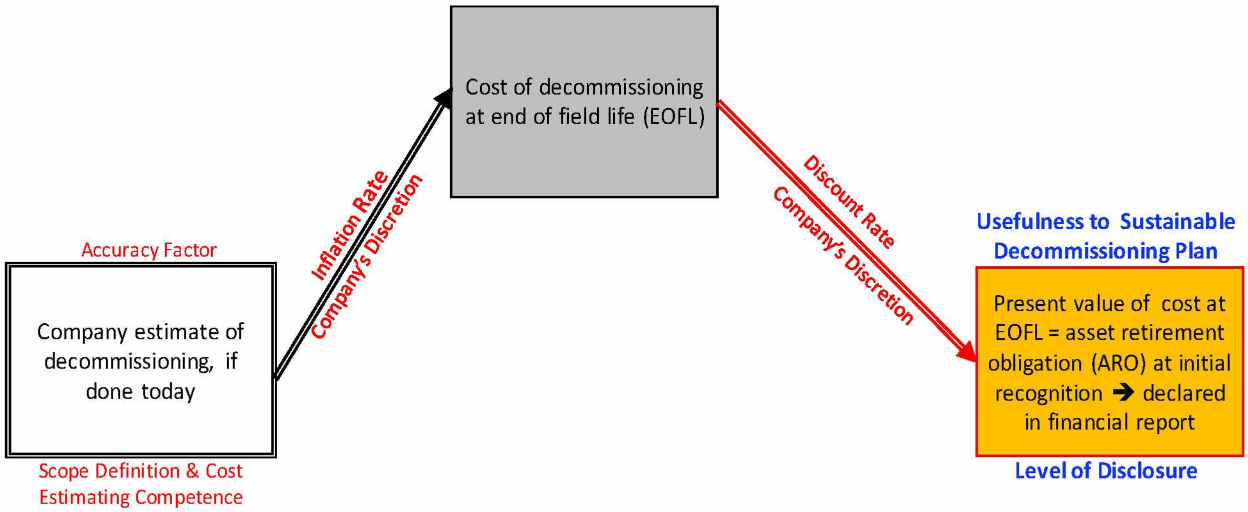


Figure 29: Determination of initial declared cost of ARO in financial reports

While the reported cost of ARO in financial reports holds an opportunity for the public to get information on the cost of decommissioning liabilities, there still exist some challenges with the clarity of the information presented. Most oil companies neither operate only in onshore fields, nor operate in only crude oil fields. Most of them have operations that cut across several countries or regions and fields. Consequently, the reported cost of ARO or decommissioning liabilities are aggregated over operations from several countries, and combined for both onshore and offshore fields. This is the predominant experience with financial reports for MOCs in Nigeria.

Companies, in most cases, do not reveal the discount and inflation rates used in determining the present value of ARO cost presented in their financial reports. Rogers & Atkins (2015) evaluated the performance of 146 oil and gas companies in the United States from 2003 to 2015 with respect to declared ARO cost in their financial reports. They concluded that most of the companies do not declare the undiscounted value, the discount rates used to determine the reported present value, or details of revisions made to their annual reported cost of ARO. Decommissioning related transactions that led to changes in the values of ARO over a period are also not clearly declared in financial reports. Hence, even if the inter-period changes to the cost of ARO are identified or inferred, the associated scope of decommissioning may still be unknown.

There could be a solution to some of these challenges, if the financial reports in question come from a company or companies that operate only in a specific region, such as onshore fields in Nigeria. The reports should have the discount and interest rates clearly stated and end of field life assumptions clearly disclosed. With business confidentiality and competition, it is challenging to gain ARO data that meet all these requirements. However, there could be some empirical situations that offer opportunities to obtain ARO data that meet these requirements to a considerable extent. Kaiser (2015b) used public information on settled ARO liabilities to infer the private cost of decommissioning for some platforms in the GOM. From the data, he developed a regression model for decommissioning cost estimates in the GOM. His approach overcame the challenge of retrieving confidential information, and provided an auditable and transparent decommissioning cost estimation process. However, details of the scope of decommissioning work completed in the reference study years for the GOM were privately accessed. Unlike the GOM, cost data for settled decommissioning liabilities may not be available for some crude oil producing regions such as Nigeria, where there are few or no completed decommissioning projects.

In addition, Nigerian accounting standards and financial reporting requirements may not be stringently implemented. However, some of the indigenous operators in Nigerian onshore fields are in partnership with foreign investors. The transparency and third-party validation requirement embedded in the reporting guidelines of foreign accounting standards and financial reporting bodies, such as the Financial Accounting Standard Board (FASB), and financial bodies, such as the Canadian Securities Administrators and the US Securities and Exchange Commission, will help incentivize the reporting of cost of ARO associated with their Nigerian operations. Therefore, the annual corporate and financial reports for crude oil companies operating in onshore fields in Nigeria could be one of the best sources for cost of decommissioning liabilities if they contain all the required pieces of information. They could provide the public with unencumbered access to these data. The small independent companies, still in their early years, have acquired only onshore fields from the MOCs and therefore, operate only onshore fields. As they have only been operating for a few years, the declared asset retirement cost elements and decommissioning scope covered in their financial reports will be easy to identify, trace, and decompose.

4.4. The Needs for Cost Estimate for Decommissioning Liabilities in Nigeria

Nigeria is still at a very early stage when it comes to the description and development of a plan toward decommissioning of its onshore fields. Literature search and investigations did not reveal any cost estimate for decommissioning of onshore fields in Nigeria. Stakeholder Development Network (2015) also made a similar observation. The investigations revealed widespread vagueness on what decommissioning entails and either denial or limited awareness of the imminent end of economic life for these fields. There is no ROM cost estimate for decommissioning liabilities to kick start a conversation on decommissioning in Nigeria. To worsen the situation, there is limited information, either in the public domain or otherwise easily accessible, to help the public understand and participate in the development of a decommissioning strategy. Smith et al. (2000) and Lawal (2008) noted that there was no recognition of any petroleum-related activities continuing beyond the production phase in Nigeria's JV agreements. As further argued by Lawal (2008), this implied that decommissioning was not thought about when the agreements were drafted and signed. Now that the EOFL for these fields is foreseeable, with attendant implications for revenue generation and sociopolitical aspects of the nation, quantifying the cost implications of decommissioning liabilities, that is, their dismantlement, removal, and restoration of the environment, has become important.

Empirical observations from the UKCS and GOM show that as the EOFL approaches, asset divestment by large operators to small operators is common. While the transfer of resources and assets could be straightforward, the transfer of ownership for decommissioning and environmental liabilities is not. Accountants and investors will prefer to know the cost of decommissioning liabilities to help them evaluate the sustainability of investment in oil companies. Investors will not prefer a field with decommissioning obligations that will be complicated to fulfill and could wipe out the expected profit from the field. As smaller independent companies that are less financially and technically robust take over operatorship of these fields, the risk of an operator defaulting on its decommissioning liabilities will increase. The smaller operators may end up failing to decommission the fields properly. This could lead to environmental degradation. In comparison to the MOCs, they may not have much corporate environmental reputation to uphold, and therefore could easily default. If an operator fails to complete the decommissioning of its facilities, the government, which by extension is the public, will have to pay for proper decommissioning of the facilities, similar to the orphan wells programs in the United States (Hesson, 2006). Otherwise, the environment will be left polluted. Hesson (2006) highlighted this problem at Eureka Canyon oil field in California, where several wells were “left orphaned when the last operators-of-record became defunct” and the state of California had to properly abandon the wells and address the resultant environmental challenges by itself. King & Valencia (2014) noted that “improperly plugged oil and gas wells, dating from 1860s to 1930s and later, are a potential threat” to ground water in some early oil boom areas.

In mature fields such as the UKCS, government policy requires operators to remove all assets, unless otherwise approved. Currently, in the UK and under the United States Superfund program, all operators that have been associated with an asset at any time in its economic life are held jointly and severally liable for the decommissioning liabilities (West, 2014; Wetmore, 2014). On the contrary, there is no similar explicit policy objective in Nigeria (Table 1). The proposed Petroleum Industry Bill (PIB) is intended to incorporate a similar objective (Dawodu, 2016). However, enforcing it on foreign-parented companies such as the MOCs will be challenging, particularly after they have divested their assets to local companies and left Nigeria. According to Schaps & George (2017), a court in the UK has held that Shell—an MOC in Nigeria—cannot be taken to a UK court in a dispute over environmental liabilities from its operations in Nigeria. A revised regulatory approach may be required for the decommissioning of crude oil fields in Nigeria. To develop and administer an efficient policy for decommissioning, the cost of meeting decommissioning and the associated environmental liabilities needs to be known by the Nigerian government and public.

4.5. Proposition – Public Amenable Methodology to Estimate Cost of Decommissioning Liabilities

For Nigeria, considering literature search and to the best of my knowledge, there is no ROM estimate or any published attempt at generating cost estimates for decommissioning and associated environmental liabilities of its onshore crude oil fields. A ROM cost estimate is a cost estimate prepared at the early stage of a project life cycle when the scope definition is very minimal and has a low accuracy range of +50% and -50%. It is a cost estimate appropriate for low level of scope definition and recommended for making high level decisions at the early stage of a project (Project Management Institute, 2013). The absence of publicly accessible cost estimates for decommissioning liabilities in Nigeria can be attributed to several factors, such as the low level of public awareness about decommissioning, confidentially of information related to decommissioning, and limited emphasis on decommissioning phase in the regulatory frameworks (Ibebuike, 2013; Lawal, 2008; Stakeholder Democracy Network, 2015). If this information asymmetry persists, it will be a recipe for public discord and an outrage when execution of decommissioning activities commences. Feidt (2012) called attention to the public discord associated with the responsibility to properly abandon the legacy wells drilled between 1942 and 1982 in Alaska. Therefore, the decommissioning of a common resource and national asset such as crude oil fields in Nigeria is a public policy issue. Walters et al. (2000), O'Faircheallaigh (2010), Marzuki (2015), and Sinclair & Diduck (2016) noted that public participation in most public policy issues is inadequate. As similarly observed by Lawal (2008), public participation has not been evident in the strategy or policy development for decommissioning in Nigeria. Among other factors, this could be attributed to the absence of publicly accessible relevant data, such as the potential cost of decommissioning and associated environmental liabilities for onshore fields in Nigeria. Given that the public, through the government, could end up paying for the decommissioning activities, awareness of the cost could help to improve the level of public participation. Therefore, providing a methodology that uses publicly accessible information to establish the cost of decommissioning liabilities will represent progress and a step toward sustainable decommissioning.

Given the public disclosure and auditing requirements associated with the cost of ARO declared in financial reports, the paucity of cost estimates for decommissioning of onshore crude oil fields in Nigeria may be addressed through the deduction of aggregate cost of decommissioning from the declared cost of ARO in these reports. Therefore, the opportunity of new companies acquiring onshore fields from MOCs in Nigeria can be exploited to generate appropriate data and determine a generic aggregate decommissioning cost estimate for onshore fields in Nigeria. These could be good take off points to quantify the decommissioning liabilities for onshore fields in Nigeria. They will also provide the public with unencumbered data access.

From investigated literatures and studies, one key objective of the cost estimation process for crude oil facilities decommissioning activities is to adequately account for decommissioning liabilities with the aim of having the operators take full responsibility of the liabilities. The process wants to prevent any slippage of responsibilities to the general public. It will seek to achieve this by having a register of these assets, defining the anticipated scope of work to completely decommission them and restore the environment back to its original state or state acceptable to the public, and determining the associated cost or financial liability to achieve this objective.

From the studies investigated, it can be inferred that estimating the cost of decommissioning liabilities will require an explicit and consistent basis, defined by a particular agency or regulatory body. The scope, unit rates, and other factors may have a stratified level of definition which could be related to the phase of the field development in the petroleum lifecycle. These cost estimates should be reviewed periodically in the light of related changes in regulation or other scope requirements. They should be consistent, transparent, easy to interpret, and their full disclosure will be the aspiration of the public and government. A good and robust decommissioning policy and implementation program is expected to contain elements that will help achieve these objectives. This will also be the characteristic of a cost estimating methodology for decommissioning liabilities expected under a mature decommissioning policy. However, the absence of information cannot be accepted as an excuse for not having cost estimates for decommissioning liabilities. This study holds that there is adequate data already in the public space to begin a discussion on cost estimates for decommissioning liabilities.

There is a need for a methodology that develops a decommissioning cost estimate from publicly declared ARO related information in corporate financial reports. This is an important need for governments and public stakeholders, particularly in countries with challenged regulatory capacities and weak institutions. It is needed by these nations to help initiate a comprehensive policy development and effective stakeholder engagement process toward sustainable decommissioning of their crude oil facilities. The absence of this methodology is also a knowledge gap in sustainable decommissioning that can benefit from more academic investigation, of which Nigerian onshore fields are a fit for a case study.

This study seeks to address this knowledge gap and answer the research question; is there a methodology to overcome information asymmetry in the petroleum industry to know the size and cost of decommissioning liabilities arising from the crude oil fields? The corollary objective is to develop a methodology to estimate and establish a high-level aggregate cost of decommissioning and associated environmental liabilities for onshore fields in Nigeria from publicly available data. This will help to facilitate discussions and policy development for the decommissioning of onshore fields in Nigeria, events that contrary to assumptions held by the public, may commence sooner than later. A model based on a public user-friendly methodology that uses publicly available ARO information for oil companies will be developed and presented as part of results from this study in chapter 9 – Results and Results Analysis. It will be a contribution toward closure of the identified knowledge gap in cost estimating for sustainable decommissioning of petroleum fields.

5. Decommissioning – Its Reserves Decline and Production Forecast Challenges

According to Szklo et al. (2007), a resource is the entire stock of natural resources in a reservoir, whether discovered or not, and exploitable or not. This definition refers to the entire hydrocarbon initially in place. On the other hand, reserves are portions of the resource which are known or discovered and at a particular point in time, are exploitable based on current economic conditions and technology. Society of Petroleum Engineers (1997) defined reserves as " those quantities of petroleum which are anticipated to be commercially recovered [recoverable] from known accumulations from a given date forward."

5.1. Reserve Estimates and Production Rates Calculation Procedures

There are several methods of estimating crude oil reserves and production rates. However, irrespective of the methods, the two major procedures used to calculate reserves estimates and production rates are deterministic and probabilistic procedures. Reserve and production rate estimation methods specify the physical parameters or factors in the equation, formula, or model used for the estimation. The calculation procedure determines if a single value will be assigned to each parameter (deterministic procedure) or different values will be assigned to each or some of the parameters based on probability distribution curves for the parameter (probabilistic procedure). Under the deterministic procedure, a single value is selected for each parameter used to determine the reserves estimate. As a result, the reserve figures or production rates generated may be represented as a single deterministic value. On the other hand, the probabilistic procedure involves assigning several values to each variable based on the probability distribution curve for the parameter. Under a probabilistic procedure, a parameter does not have a single value, but a range of variable values randomly selected based on a probability distribution for the parameter. The reserve figures, similar to all results from probabilistic procedures, are expressed as distribution curves with values corresponding to different level of confidence or probabilities that the volume of exploitable oil will be more than a certain amount. Similarly, the production rate forecasts represent the probability that the expected production rate will be more than a certain value of production rate (Kosova et al., 2015; MacKay, 2004; Petrobjects, 2004). Consequently, the results from probabilities procedures can be expressed in different classes of reserve and production rate estimates.

5.1.1. Reserves and Production Rates Classification

There are several reserve classification systems based on the probabilistic methods. Society of Petroleum Engineers (2005) identified eight different classification systems globally, which compelled SPE Oil and Gas Reserves Committee to undertake a study to consolidate the different systems. SPE's objective was to determine an internationally acceptable classification system. For example, the Russian petroleum classification uses an "A + B + C" scheme. The "A" category refers to reasonably assured reserves, which are not exactly the same but similar to P90 estimates in the SPE classification scheme. The "B" category refers to identified reserves, the "C1" refers to estimated reserves, and "C2" refers to inferred reserves. The SPE system and as commonly applied in the industry, will be adopted in this study.

Under this system, the P90 or 1P reserve estimate, which is the proven reserve, refers to 90% probability that the actual exploitable volume will exceed a certain volume. Hence, it is the smallest quantity of the three probable volumes given for a field. The 2P or P50 is the proven plus probable reserves, which refer to the volume that could be exceeded with a probability of

50%. This is the medium number and commonly given probabilistic estimate for a reserve. The 3P or P10 is the proven plus probable and possible reserves. It refers to the volume that could be exceeded with the probability of 10%. This is always the largest of the three estimates. These probabilities consider detailed information on technology, price, and even sociopolitical environment of business into consideration. Therefore, the P90 data becomes the most conservative data for planning purposes. This classification for reserves also applies to forecasted production rates (Hook, 2009). However, the level of detailed information required for results with a higher level of confidence is not readily available for most fields due to trade secret issues. Therefore, most often, the figures issued to the public may be assumed to be P50 or P10 depending on the objective of the analysis. For these reasons, this study will assume the numbers to be P50. Consequently, it is challenging to exactly estimate the size of reserve, but even more challenging to estimate the size of the resource.

5.2. Reserves and Reserves Depletion

Considering the relative importance to decommissioning, depletion studies will be more focused on reserves depletion than resource depletion. As defined earlier, depending on economic factors such as price, demand, and technology, a resource, or portion of the resource, may become a reserve. This gives rise to the idea of possible momentary increase in the recorded stock of oil reserve over the life time of a field or region as a result of emergence of new technologies or favorable economic conditions. These increments notwithstanding, the stock of entire resource does not increase even with technology as crude oil is finite and exhaustible. Crude oil as a finite non-renewable natural resource will be exhausted at some point in time, if it is continually exploited. Therefore, reserves depletion behavior is important for the management and planning of decommissioning.

Crude oil production decline and reserve depletion have been widely studied. According to Spencer (2004), in his editorial for Re-focus magazine, the analysis of oil depletion has gone on to a point that declining oil production from entire countries as opposed to individual fields or regions is now a great concern. Aleklett & Campbell (2003) observed that an essential feature of oil depletion behavior is that the higher the production rate, the shorter the life span of the field extraction. The authors argued that rather than final exhaustion, the main issue of concern should be the peak period when high production and growth of the past will be replaced with decline into the future. They submitted that we need to know the time available to prepare for this change. Considering the challenges with knowing the exact time of occurrence of peak production and realizing that exactitude is not necessarily required for decommissioning policy and strategy development, this study holds the proposition that an approximate range of time period for the occurrence of peak production or in the alternative, the remaining economic production life, will be sufficiently good for policy making and planning purposes. Considering the empirical political experience and protracted nature of public policy development and implementation in Nigeria, at least 2 to 4 decades will be a good lead time. Nigeria's new PIB has been in drafting and development stage for almost 2 decades and yet to be enacted (Okafor, 2017; Osibanjo, 2016).

5.3. Crude Oil Reserves Depletion – Patterns, Drivers, and Contributing Factors

To determine an approximate range of time period for occurrence of peak production or the remaining economic production life of a field or region, an understanding of the drivers behind crude oil reserve depletion is required. Miller et al., (2009), and Miller & Sorrell (2013) defined a depletion rate as how rapidly the remaining resources in a field or region can be produced. Sorrell et al. (2010) explained that depletion is the portion of an estimated and ultimately recoverable resource which has been produced. Therefore, it connotes that a depletion rate is the annual rate at which the remaining recoverable resource in a field or region is produced. It is the ratio of annual production to some estimate of recoverable resource or proved reserves or total reserve used for planning purposes. Therefore, the depletion rate r_d is a ratio of annual production P to the amount of reserve R at the beginning of the year, that is

$$r_d = P/R \qquad \text{Equation (1)}$$

For clarification purposes, it is will be helpful to differentiate between depletion rate and rate of production decline

Production decline rate is the rate of change in production rates between reference years or periods, this is, $(P_1 - P_2)/P_1$ where P_1 is the total production volume for the first year or period and P_2 is the total production volume for the second year or period. From this perspective, changes in production rates, particularly a decline, may not necessarily reflect a commensurate reserve depletion rate, if the changes are not particularly due to natural reserve depletion. Production decline does not always mean reserve depletion. The changes in annual production rate may be due to technical or political factors. However, where the production rate changes are majorly driven by natural phenomenon such as reservoir pressure changes and depletion, then production decline may reflect reserves depletion (Hook, 2009; Jakobsson, 2012).

Simmons & Pursell (1999) provide a more explanatory definition of reserves depletion as a phenomenon where oil and gas wells exhibit decline in production over time due to drop in the reservoir pressure. They explained that even in reservoirs where the pressure is maintained through water or other fluid injection mechanisms, the amount of crude oil produced relative to produced water content reduces over time, that is an increase in water cut. This occurs even when the reservoir pressure is maintained relatively constant due to the injected fluid. They listed aggressiveness of field development programs such as increasing the number of wells in a field, as one of the factors influencing depletion.

While natural phenomena may drive the limits of production, economic and technical factors could still influence the reserve depletion. However, at some point, natural phenomena will dominate the economic factors and technological influences. The field will then be on an irreversible and consistent decline path. A close observation of production profiles from Nigerian onshore fields (see chapter 3) shows that the fields are already in the decline phase. This supports a proposition that the fields are already on the pathway to imminent decommissioning. Therefore, the physical forces driving reserves depletion are of interest in this study.

5.4. Depletion Driving Forces

The crude oil reservoir pressure system is a complex system of interplays between different force mechanisms. Hook (2009) classified the driving forces behind depletion into two categories, namely (i) direct depletion mechanisms, which are tied to natural phenomena and physical laws governing reality, and (ii) indirect depletion mechanisms, which are not necessarily directly tied to natural laws of physics as highlighted in Table 5.

5.4.1. Direct Depletion Mechanism

Direct depletion mechanism is related to the physical phenomenon of porosity, buoyancy, fluid mechanics, and physics of pressure-volume system. In simple terms, for crude oil to move from the reservoir to the surface, there must be a continuous pressure system with an adequate pressure difference between the reservoir and destination of the crude oil. As production continues, pressure or energy will be expended to move the oil to its destination, leading to a drop in the reservoir pressure or energy. The drop in pressure will imply a drop in pressure gradient between the reservoir and destination of the crude oil. According to Darcy's law, this will reflect in the reduction of production flow rate. Darcy's law states that

$$u = -(\mathrm{k} \times dP \,/\, u \times dl) \qquad \text{Equation (2)}$$

where "u " is the velocity measured in cm/seconds, "k" is a constant in Darcy, u is the viscosity in centipoise, and dp/dl is the pressure gradient in "atm/cm."

Considering Darcy's law, the production decline rate will be in some direct relation to the reservoir pressure depletion. If additional energy, such high pressure water, is injected into the reservoir, then the reservoir pressure will increase and total fluid production may be sustained, albeit for a short period and the production decline will commence again, unless water injection continues.

Hook (2009) noted that direct depletion driven production decline is a reduction in production rate due to exhaustion of the recoverable reserves and physical limitation of porosity and permeability of the reservoir. It is challenging to compensate for this type of production decline as porosity and permeability are relatively natural phenomena. There is a limit to which fracking can improve permeability. The physical limits of the reservoir and physical factors such as porosity, permeability, and other geological parameters will always set limits on how much of the production decline can be compensated even with external energy given to the reservoir. Therefore, production decline rates and depletion rates can be very closely related, if direct depletion mechanisms dominate the decline pattern of a field or region. This is the situation with most mature fields. The phenomenon can be explained using the laws of physics and nature, and hence future reservoir system behavior and production rates can be predicted with mathematical and physical models such as decline curve models.

5.4.2. Indirect Depletion Mechanism

In contrast to the direct depletion mechanism, there are other factors capable of driving depletion indirectly and causing decline in production rate, which is described as the indirect depletion mechanism. For example, economic factors such as prices, availability of capital, or political situations like war, can influence how much of a reserve is exploited in a particular time. Therefore, oil production from a region may not be solely explained on the basis of direct depletion mechanisms, particularly at early production phase. It may be driven by one or combination of indirect depletion factors, such as economic, market, or political factors. Isolating these factors can be challenging as they are not natural or physical phenomena. They cannot be explained in terms of natural science and mathematical correlation alone. For example, in the early production phase, production decline rate and its face value cannot be regarded as a robust indicator of resource exhaustion (i.e., reserve depletion).

However, as onshore fields in Nigeria are already in post-peak production, it will be tenable to assume that direct depletion mechanism is dominant in the reservoir systems.

Table 5: Comparison between reservoir depletion mechanisms

Depletion Driving Forces or Mechanisms: Types	
Direct Depletion Mechanism	**Indirect Depletion Mechanism**
Natural laws of physics – pressure depletion, porosity etc.	Non-natural factors – economic, political etc.
More predictable	Less predictable

5.5. Estimation Methods for Reserves and Production Forecast

Both direct and indirect depletion mechanisms and associated drivers have been incorporated into different methods of forecasting of future crude oil production rates and reserve values. The preferred method will depend on the objective of the forecasting exercise. This in turn will set the level of accuracy, reliability, effort, amount of data, and skills required to develop the forecast models.

Literature abounds with several methods for calculation and determination of reserves and future production rates for oil and gas fields and regions. MacKay (2004) identified three methods or techniques for reserves estimation, which include volumetric, material balance, and production decline analysis. Demirmen (2007) classified them to be analogy, volumetric, and performance methods, while Petrobjects (2004) puts them into six groups – analogy, volumetric, decline analysis, material balance calculation for oil reservoirs, material balance calculation for gas reservoirs, and reservoir simulations. Brandt (2010), in his review of mathematical models for determination of production decline rates, noted four main methods. These are (i) the simple models of oil depletion, which include the RtP, depletion rate, reserve replacement ratio (RRR) and curve-fittings models, such as Hubbert's model, which is a bell-shaped curve developed by Hubbert in 1952; (ii) system simulations, which use factors like resources discovery rates and technology success rates; (iii) bottom-up models consisting of building up oil depletion from the individual field levels, and (iv) economic models of oil depletion, such as Hotelling models and econometric models. Aleklett & Campbell (2003) also identified similar methods, such as the depletion modeling method, creaming curve method, (these two aforementioned methods are similar to the curve fitting models described by Brandt), and parabolic fractal and pragmatic model methods (similar to the bottom-up and economic model methods also described by Brandt). De Almeida & Silva (2009), in their study of peak production, identified several predictive methods, which include (i) "business as usual" method, which holds that oil consumption will simply go on following historical growth and not be depleted, (ii) "bottom-up analysis," which involves the use of specific data at the individual well level to predict production of all wells in a field which are further aggregated into a field wide production forecast, and (iii) fitting curves, which fit parametric oil production curves on observed historical production profile and then adjust it to gain the ultimate recoverable reserves. Rehrl & Friedrich (2006), and Szklo et al. (2007), from an economics perspective, concurred that the most widely applied models for modeling oil supply are the Hotelling model based on Hotelling principle and Hubbert's model. Other authors, such as Jakobsson (2012), Lynch (2002), and Poston & Poe (2008), looking from a physics perspective, will hold that production decline curves are the most popular.

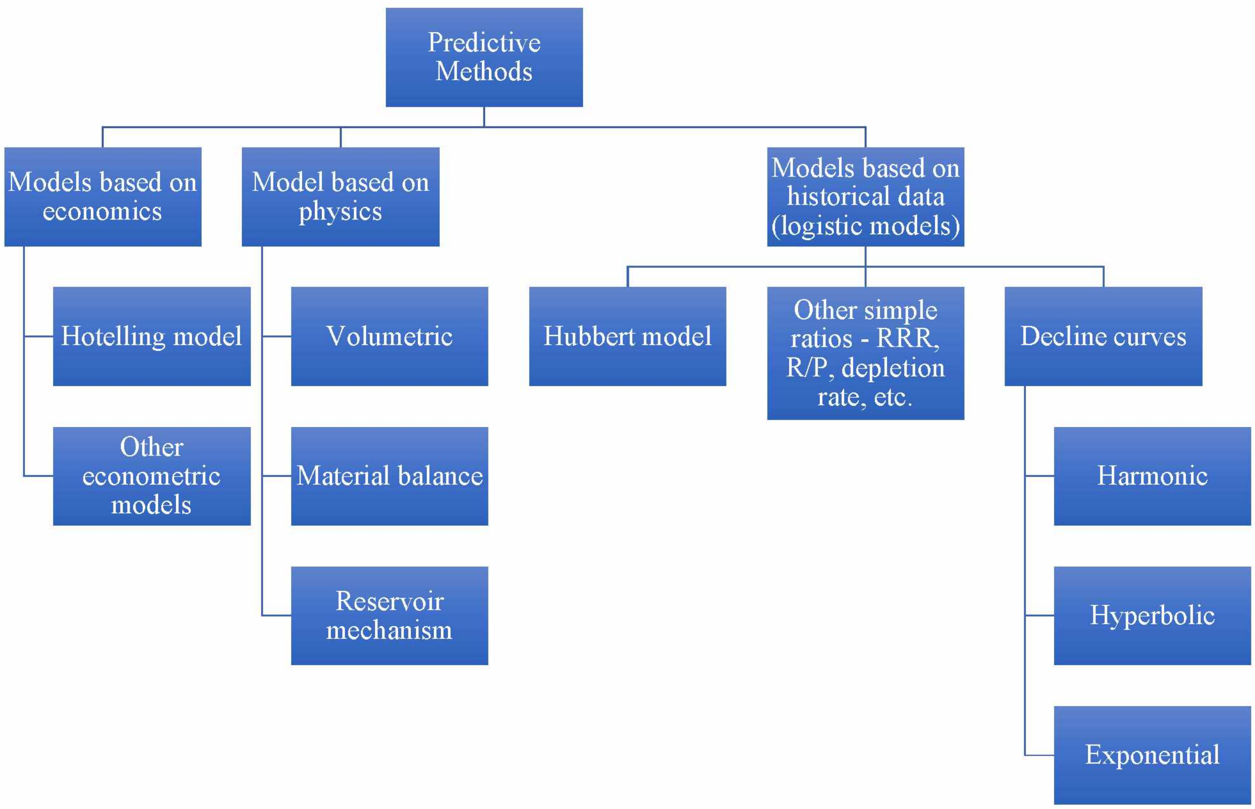


Figure 30: Predictive methods

An evaluation of the methods revealed that most of them can be categorized under three main modeling methods based on the type of input data required, as illustrated in Figure 30. They are (i) models based on economics, such as market place and price data which mostly rely on the principles of economics, (ii) models based on physical properties/data, which rely mostly on physical and natural properties, and (iii) models based on empirical/historical production data, which mostly rely on historical production data with presumed underlying dominant effect of physical properties and natural factors in the reservoir production system. These models assume that direct depletion mechanism is the dominating depletion driving force.

5.5.1. Models Based on Economic Data (Economic Data Modeling)

The methods under this category involve the use of principles of economics and modeling of economic data to represent the relationship between behavior of empirical cumulative discoveries or production rates, and economic behaviors/variables such as oil price, price elasticity of supply, and demand. The relationship is then used as a basis to forecast future supply or production. There are several econometric models based on different structural econometric relationships of demand, supply, price, and market equilibrium. The most popular models are based on the Hotelling rule, which has several modified and adapted versions.

5.5.1.1. Hotelling Principle and Associated Models of Natural Resource Extraction Path

Hotelling (1931) looked at non-renewable resources from a free and non-monopoly market competition perspective. He explained that the price of a non-renewable resource will follow an econometric relationship expressed mathematically as

$$P_o = P_t e^{rt} \text{ or } P_o / P_t = e^{rt} \qquad \text{Equation (3)}$$

where "r" is the interest rate of return or discount rate, "t" is a chosen future time, "P_o" is the initial price at initial time "t_o," and "P_t" is the price at a chosen future time "t."

Therefore, “P_o” is the present value of the future price, “P_t” of the stock of the natural resource. Gaudet (2007) noted that in situ, oil as a natural resource is treated similar to a capital asset whose value is dependent on its expected rate of return. The value of the remaining stock at any time will appreciate like a capital asset. Its value will be largely enhanced by the opportunity cost of the forgone future use of a unit exhausted today. This opportunity cost is described as scarcity rent and the price of the non-renewable resource will rise as illustrated in Figure 31, until a new technology — backstop technology — replaces it.

Based on Hotelling principle, Marshalla (1977) stated that the theory of deplete-able resource characterizes a time path of scarcity rents which, if added to the extraction cost, would lead to an efficient consumption pattern of a non-renewable resource. As such, the optimal rate of depletion according to Hotelling principle will seek to maximize the price or benefits from the stock of natural resource accruable to the owner.

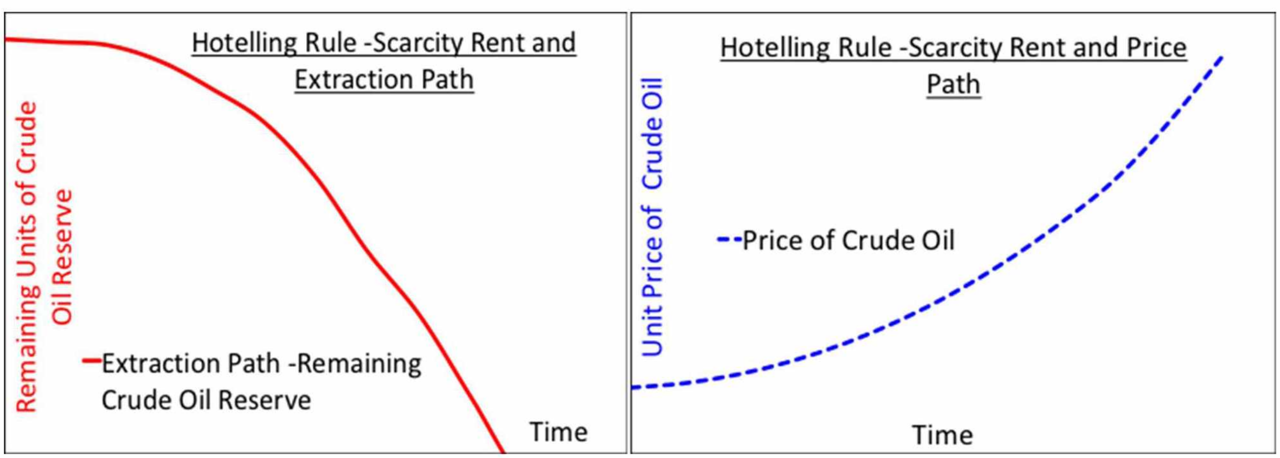


Figure 31: Hotelling rule – Price and extraction path

In an attempt to establish a relationship between scarcity rent and production profile, Marshalla (1977) expounded on Hotelling rule and implied that scarcity rents must grow at the same rate of return accruable from a comparable capital asset in the same class of risk as the oil resource. With a comparable asset and similar conditions, a competitive resource owner will be at a point of indifference between the choice of either extracting the resource or leaving it in the ground. Therefore, the optimal depletion rate will be the rate that seeks optimal benefits from the natural resource. However, Gaudet (2007) noted that it is not only anticipated price appreciation or movement that can drive the resource owner's decision to extract or not to extract. Gaudet suggested that factors such as extraction cost, durability of natural resource, market structure, and other uncertainties also characterize the rate of return. Gowdy & Julia (2007) proposed that any technology that will reduce the extraction cost will increase the benefits to the owners. They proved this with an empirical and historical study of two mega fields, North Sea Forties field and Texas Yates mega field. In their study, they held that technology does not necessarily "offset the declines in production reserves" but instead does marginally alter the path of depletion and increase production at the cost of "pronounced rates of depletion in later years." It only leads to a push forward of the peak oil period. Either way, economic models are attempts to combine price with other factors to estimate a production profile for a field based on principles of economics, such as the Hotelling principle.

Proposition

The Hotelling model is more of a price forecasting model than a production profile forecasting model. The rule speaks more to the role of price as a reflection of scarcity in the non-renewable natural resource market. As pointed out by Gaudet (2007), and Gowdy & Julia (2007), other factors besides price affects the choice to extract or not to extract a resource, and hence the depletion profile. In addition, there are several assumptions with the Hotelling rule that are challenging to validate. Hotelling rule assumes that the original size of the non-renewable natural resource is known, market participants have a perfect knowledge, and the non-renewable resource stock cannot be increased, meaning that all there is, has been found. Real world experience has shown that implicitly, none of these assumptions hold in the real world. Andersen et al. (2014) used empirical data from oil production in Texas from 1990 to 2007 to prove that “observed patterns of oil production and prices are not compatible with Hotelling [rule].” With situations like the existence of Oil Producing and Exporting Countries (OPEC), the oil market has some elements of oligopoly, and hence participants cannot have perfect knowledge.

Mohaddes (2013) concluded that “ Hotelling model and its extensions develop theoretical models that yield predictions governing the rate of change of oil prices, but on their own they are not able to determine the level of oil prices or the profile of oil production in the world economy.” According to Reynolds (2013), irrespective of its popularity, the application of the Hotelling rule in a real market situation is challenging as “ the costs, benefits, and transversality conditions of using the Hotelling rule can be highly non-linear” It also requires the application of discount rates over a long period of time which are unpredictable.

Using Hotelling rule for production forecast is not only fraught with challenges of unpredictability, but is complex. Policy development and planning for decommissioning in developing countries with weak institutions, such as Nigeria, requires simple transparent models, particularly when they are focused at a macro level, such as the entire onshore fields in Nigeria.

Models based on Hotelling rule will be not be sufficiently simple and transparent to support policy development and planning at a macro level, particularly for a developing nation like Nigeria with weak policy implementation agencies.

5.5.1.2. Other Economics Based Models

Cynthia Lin (2011), Kemp & Kasim (2003), and Naser (2014) amongst several authors presented other types of economic models based on variables such as GDP and oil price. One of the objectives of these economic models is to determine the equilibrium pathway through which crude prices and crude oil quantities are determined by the market forces. However, as concluded by Cytnhia Lin (2011), "attempting to efficiently and consistently estimate aggregate oil supply and demand market in the context of a static and perfectly competitive oil market" is challenging owing to the " non-plausibility of the static perfect competition assumptions in the first place." Most of the models have problems with identification of input data. The value of supply and demand function varies with the market and does not help in arriving at a simple relation for the purpose of predicting crude oil production rates.

Jakobsson (2012) observed that despite improvement made to these models over the years, their predictive performance have "not been particularly good." Lynch (2002) also held the view that the factors influencing oil production at both disaggregate and aggregate levels are so many that "econometric model of drilling, reserve additions, capacity additions, and production is unlikely to be successful," particularly where a simple but reliable production forecast will be adequate for an issue such as the development of a sustainable decommissioning policy in the Nigerian petroleum industry.

5.5.2. Models Based on Physics

Models based on physics are premised on the natural phenomena of fluid properties, fluid dynamics, and energy balance. Laws of physics and nature are supposed to be reliable in their exercise, hence should yield reliable forecast, if actually applicable to a phenomenon. Poston & Poe (2008) conducted an extensive study on predictive models for oil production. Similar to Hook (2009), but with some marginal variations, they identified four main types of predictive models for oil and gas production rates. They are (i) volumetric models, (ii) material balance, (iii) reservoir simulations, and (vi) decline curve models or analysis (DCA), which Hook (2009) also identified. The first three are models based on the laws of physics, while the last model type, that is decline curve analysis, is based on empirical data/history which presumed dominant effect of underlying laws of physics. For the purpose of this research, DCA will be considered and evaluated under logistic and empirical methods in section 5.5.3.

Volumetric models are based on the use and analysis of static and core logs to calculate the original oil in place. An empirical recovery factor or a recovery factor based on some rule-of-thumb is applied to determine the oil production rates. However, in terms of disadvantages, it cannot predict future productivity and degree of drainage homogeneity, and hence not suitable for dynamic forecasting. Its results are a function of well spacing, porosity, and saturation.

Material balance methods are based on the principle of conversation of mass and include production history, pressure-dependent rock, and fluid properties. The model does not include variable flow conditions and as such, requires application of a recovery factor to determine volume of reserves, which introduces an uncertainty. This method is data intensive and will be too complex for the public and less mature institutions in developing countries such as Nigeria. Challenges with data acquisition and interpretation for parameters such as rock and fluid properties could discourage stakeholders' participation.

Reservoir simulation involves division of the reservoir into grid systems for the iterative application of material balance equation, diffusivity flow equation, and equation of state to calculate the depletion history of each grid cell. It can be applied in either two or three dimensions (2D or 3D) and variation can be easily predicted. Hence, it provides a better prediction of future performance. However, it is complicated to understand and prepare, requires a lot of data, longer time and effort to be completed, and attracts high cost. Rock heterogeneities and geology is forced fitted to match the computer model, hence leading to over-simplification and inherently poor quality of output data (Poston & Poe, 2008).

Even though largely based on the law of physics, there continue to be some non-physics data relationship imputed into these predictive models. They require data manipulation skills and techniques, which non-specialist stakeholders may not easily understand. A crude oil decommissioning policy, particularly at the initial stage, will require models that the public, particularly non-specialist stakeholders, can easily understand. Input data should not attract high transaction cost which tends to discourage public participation in the policy making and implementation process (Adhikari, 2001; Anderson & Parker, 2013; Coase, 1960). Crude oil is a natural and common pool resource in Nigeria and its extraction affects the social welfare. Stakeholders' participation in its decisions is necessary to achieve sustainable development objectives. Easy access to necessary information, such as production profile and cost of decommissioning liabilities, will encourage effective stakeholder participation. Economics and physics based models will pose several challenges to non-specialist stakeholders and the public in the areas of data acquisition and interpretation, and therefore not amenable to this objective.

5.5.3. Models Based on Logistic and Historical Production Data

Models based on empirical production and reserve data include (i) simple ratios such as reserve to production (RtP), depletion rate, and reserve replacement ratios (RRR), (ii) Hubert model curves, and (iii) decline curves or DCA. These models consider historical data and use them to predict future production. Their main predictive basis is the historical pattern. Their advantage is that they are not complex to understand and could incentivize public participation in decommissioning policy development, planning, and implementation. One disadvantage is that the prevalence of conditions where history does become dominant into the future needs to be established before they can be used to make reliable forecasts.

5.5.3.1. Simple Ratios – Reserves to Production (R/P) Ratio, Depletion Rate, and Reserve Replacement Ratio (RRR)

Reserve to production ratio (R/P or RtP) could be a form of indicator for sustainability of petroleum resource extraction. It provides an indication of how many years or duration that production can continue at the current rate before exhaustion of the available reserves. If P_{t-1} is the cumulative production for the previous year or target cumulative production and R_t is the remaining reserves at the beginning of the year "*t*", then the *R/P* or *RtP* is

$$R_tP = R_t/P_{t-1} \qquad \text{Equation (4a)}$$

expressed in years of number of unit periods.

Depletion rate or ratio is the inverse of RtP ratio. It is the percentage of the current remaining reserves produced per period or year. If P_{t-1} is the cumulative production for the previous year or target cumulative annual production and R_t is the remaining reserves at the beginning of the year "t", then the depletion rate is

$$P_{t-1}/R_t \qquad \text{Equation (4b)}$$

which is expressed in percentage.

If there are no reserve additions, sustaining a current production rate will lead to an increase in the depletion rate. To maintain the current production rate, the depletion rate should match or be lower than the reserve growth rate. Otherwise, the depletion rate rises as (i) the field gets mature, (ii) remaining reserves are diminished, (iii) new reserves are not added (no reserve growth), and (iv) production rate is not reduced.

RRR represents the amount of new barrel of reserve found for every barrel produced. If the production in year "t" is "P_t" and reserves are "R_t", and reserves in the previous year "$t-1$" is R_{t-1}, then

$$\text{RRR} = (R_t - R_{t-1})/P_t \qquad \text{Equation (5)}$$

This is one of the indicators of how sustainable the current rate of extraction may be for a region or resource owner. An RRR of less than one or less than 100% means the nation or region is not increasing its reserve as fast as it is extracting from them. Ultimately, crude oil being a finite exhaustible resource, will reach a point in time when the RRR will be less than one and will continue to decrease further.

All the three methods are simple and lack rigors that reflect reality. The production rate may change in the future, and hence it is not realistic to assume that production and depletion rate will be maintained. Even with OPEC quota, member countries are not known to maintain allocated production quota. It is not realistic and sustainable to expect operators to maintain a production rate, except as constrained by the installed and functional production capacity.

5.5.3.2. Hubbert's Model and Optimal Depletion of Oil Reserves

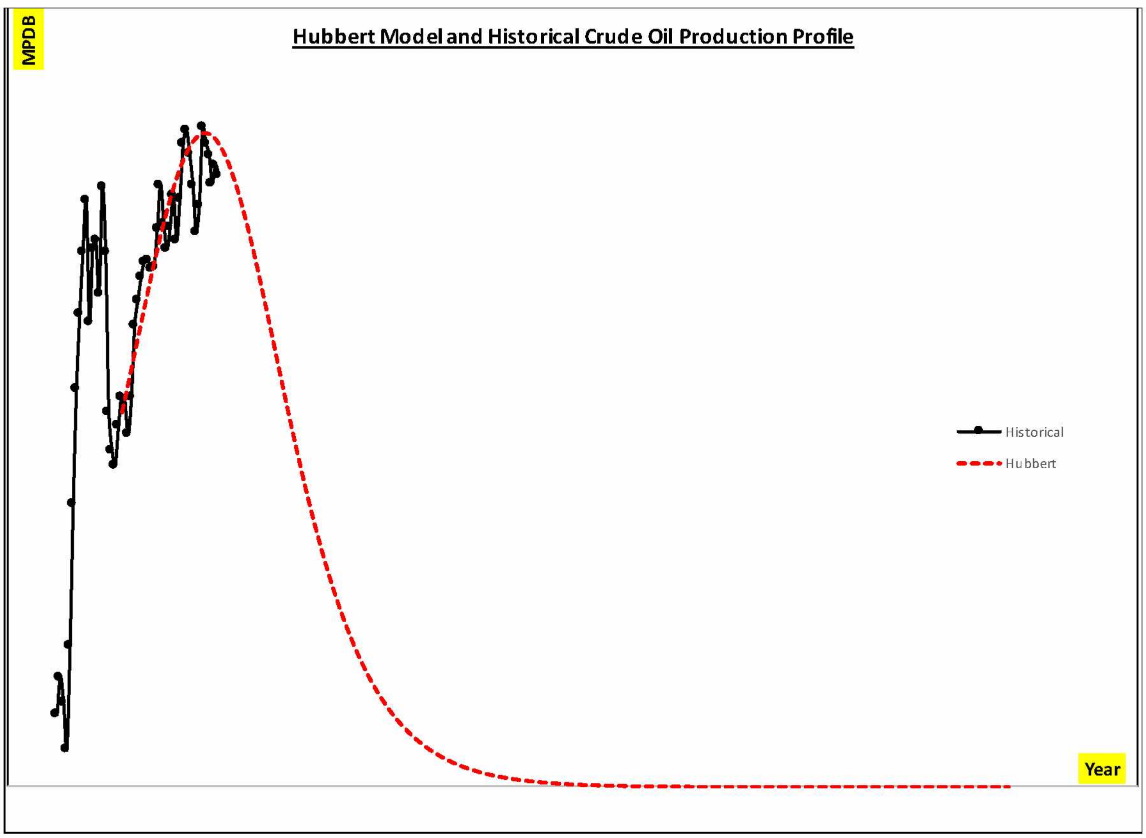


Figure 32: Hubbert curve

Hubbert's model resulted from the analysis and production forecast for crude oil in the lower 48 states of the United States and was undertaken by Hubbert for the US Geological survey in 1956. His report in 1956 showed that oil production from the lower 48 will peak between 1965 and 1970, and thereafter be on a continuous decline. History proved him to be approximately accurate when crude oil production from the lower 48 states of the United States peaked in 1970 and has since been on the decline, until the emergence of unconventional shale crude oil production in the 2007. A typical Hubbert's model will have a bell-shape profile, with a peak as illustrated in Figure 32.

Al-Jarri & Startzman (1997) in applying the Hubbert's model to production forecast, expressed production rate q(t) or dN_p/dt as a quadratic function of cumulative production, hence

$$q(t) = (dN_p/dt) = aN_p + bN_p^2 \qquad \text{Equation (6)}$$

where N_p is the cumulative production and "a" and "b" are constants.

They further determined a mathematical expression for the maximum rate (peak oil rate) q_{max} and the time at which the maximum rate (peak oil rate) will occur, which is the peak time, t_{max} (Equations 7 and 8)

$$q_{max} = aN_{p,u} /4 \qquad \text{Equation (7)}$$

$$t_{max} = t_0 +[\ln(N_D) /a] \qquad \text{Equation (8)}$$

where $N_D = (N_{p,u} - N_{p,0})/N_{p,0}$, $N_{p,0}$ is the cumulative production at an arbitrary time t_0 and $N_{p,t}$ is the cumulative production at any arbitrary time "t."

According to Al-Jarri & Startzman (1997), these mathematical equations for Hubbert curve will hold if (i) the demand for any exhaustible resource begins at zero and must decline again to zero after passing through one maximum point, (ii) total demand is equal total supply, and (iii) area under the demand-time curve is equal to the ultimate need or cumulative demand of that resource as time approaches infinity. There have been attempts to use these mathematical equations to determine the depletion profile, peak time, and peak rate of oil production for several countries based on historical production and demand data that were readily available. Al-Jarri & Startzman (1997) acknowledged that reserve depletion trends from Hubbert curve did not perfectly fit with historical production profile for several countries due to significant events, such as wars, political conflict, and economic or exploration strategies that disrupted exploration and production. Changes to the volume of initial reserves have significant impact on Hubbert's model. Therefore, knowing the initial size of the reserve to use is important, but a challenge to the application of Hubbert's model to the production rate and reserve estimation.

Al-Jarri & Startzman (1997) held that although this approach has several known inadequacies, it has withstood the test of time in numerous cases and is considered to be a fairly reliable supply predictor. Likewise, De Almeida & Silva (2009) stated that irrespective of the limitations, it is still the most commonly used model for prediction of peak oil date. Moroney & Berg (1999) argued that Hubbert's model is more appropriate for the determination of the optimal depletion rate. Beenstock (1977) used a similar depletion model for crude oil resources in the UK. The model is relatively not simple. It requires a series of assumptions and adjustments to data, making it very data sensitive, and as such may require frequent update as new data become available. Expertise and information asymmetry is biased in favor of the government and MOCs, and to the disadvantage of public stakeholders. Therefore, this model will attract high transaction cost for the public, which will deter effective public participation in the decommissioning policy process in developing countries, such as Nigeria.

5.5.3.3. Production Decline Curves or Decline Curve Analysis (DCA)

According to Hook (2009), decline curve analysis or DCA involve fitting equations of lines to match historical production and extrapolating to get future production based on the fitted historical decline curve. Ahmed (2006) described DCA as a method "based on the assumption that past production trends and their controlling factor will continue into the future." Therefore, if the behavior can be expressed in terms of a mathematical relation, it can be used to forecast future production. DCA is a mathematical equation of line based on historical production data. It is important that the historical and anticipated data are for periods when the reservoir has a stable behavior or at the post transient state of a well or field. Ahmad (2006) noted that DCA should not be used when wells and reservoirs are in transient and unsteady state conditions, such as when a well is first opened.

Poston & Poe (2008) studied the history and development of decline curves which began around 1908 when Arnold & Anderson developed the first decline curve for some California wells and became advanced through the works of Arps in the 1950s. Arps, as referenced by Poston & Poe (2008), categorized decline curves into three main categories, namely harmonic curves, hyperbolic curves, and exponential curves based on closed boundary flow conditions. Dimensionless relationship between historical data points can be generated for decline curves. Arps undertook an empirical study, which resulted in a general decline curve equation.

$$\frac{d(\ln q)}{dt} = \frac{D_i}{1 + bD_i t} \qquad \text{Equation (9)}$$

where $b = \frac{-d}{dt}\left(\frac{q}{dq/dt}\right)$ is a constant.

The constant “b” can have the value 1 or 0 or $0<b<1$.

This relationship can also be expressed as a decline rate-time relationship

$$q_t = q_i/(1 +bD_it)^{1/b} \quad \text{Equation (10)}$$

where q_t is the production rate at time t; “q_i” is the production rate at an initial or reference time when the reservoir is at post-transient state; D_i is the decline rate; “t” is the time; and “b” is a constant factor that describes the type of decline curve in operation in a reservoir system.

Table 6: Different types of decline curves and factors

Exponential	“b” =0	$q_t = q_i \exp(-D_it)$
Hyperbolic	0 >”“b” <1	$q_t = q_i/(1 +bD_it)^{1/b}$
Harmonic	“b” =1	$q_t = q_i/(1 + D_it)$

Several other authors including Camacho & Raghavan (1989), Fetkovich (1980), and Poston & Poe (2008) further studied decline curves to come out with distinguishing features based on types of reservoir transient and boundary flow conditions. The decline curve establishes the relationship between the production rate “q” and decline rate “D”. The value $b=1$ defines a harmonic decline curve relationship, $0<b<1$ defines a hyperbolic curve relationship, and $b=0$ describes an exponential curve relationship, which are the main types of decline curves as shown in Table 6.

Exponential decline curve is the most popular and easiest as it is based on the assumption of a constant decline rate. Most wells and reservoirs will witness a constant decline rate over a longer time in their lifetime. Based on the rate-time relationship developed by Arps and others, for exponential decline curve, the factor $b = 0$.

Harmonic decline curve does not constrain flow as much as exponential curve. Amongst the three, it is the most optimistic and the factor “b” =1.

Hyperbolic decline curve has a faster decline rate in comparison to harmonic decline curve where the value of the exponent “b” is $0 > b < 1$.

The results of DCA have been used for production forecast and even reservoir management, when appropriately calculated. They are relatively simple, easy to understand, and not data intensive. The mechanism behind the fitted equation of line is based on physical properties, established dominance of direct depletion mechanism in fields and the occurrence of post-peak production phase in the region or field.

Comparatively, Hubbert’s model lacks rigor and econometric models such as Hotelling models are complex and biased toward price and less on other physical factors affecting production. As a result, models such as production decline curves are relatively easy, more representative, and transparent for policy planning purposes. They use historical production data as input data, which are easy to acquire. They are based on natural phenomenon in reservoir systems dominated by direct depletion mechanism, which is expected to play into the future. For long term forecast of a region or as an aggregate of many fields, errors in individual wells and fields may become attenuated and inconsequential to high level inferences and policy decisions.

The challenge lies in how to know if a region is already in a phase where its production decline is direct depletion driven. Hook (2009) undertook an extensive study on resource exhaustion, in which he found that depletion rates can be studied to determine when production decline phase will begin to set in. He proposed that "at certain depletion rates, […] depletion-driven decline caused by extraction of the recoverable oil will begin to dominate over other production methods and force an entire field output into decline." In such conditions, a production decline curve can be a good tool for realistic assessment of reserve depletion rate. It will closely match reserves depletion rate and can therefore be a reflection of resource exhaustion as the depletion is predominately driven by natural physical phenomena. Using DCA, Hook (2009) noted that a strong connection exists between physical models for reservoir flow and empirical studies. From empirical studies, the limit of production rate or peak rate occurrence in a field or region closely matches the beginning of dominance by direct depletion mechanism over indirect depletion factors. He called out three fundamental factors that drive production rate to reach its limit and peak in a region. They are (i) distribution of field size, particularly if a small number of large fields account for a greater percentage of production from a region, (ii) geophysical performance of oil reservoirs, and (iii) timing of large and small discoveries that tend to put discovery and production of large fields before small fields. While the production decline curve after attainment of peak production rate can be used to predict reserves depletion, predicting the peak date can be challenging. Hubbert's model can be used to predict the range of time for occurrence of peak production, but it is more re-assuring if the peak production has already occurred and it is empirically observed before applying the DCA. Further, the DCA can then be reliably used to predict production rates for subsequent years and for long term planning purposes, which is the situation with Nigerian onshore fields. For example, large fields, such as Nembe, Afiesere, Eriemu, Olomoro/Oleh, Oweh, and Kokori, were discovered approximately 50 years ago and have been exhaustively exploited. They have attained peak production and continuing production decline is evident.

One other major advantage of the DCA is that it is almost independent of size or shape of reservoir or actual drive mechanism (Hook, 2009; Poston & Poe, 2008). Therefore, it does not require detailed reserve estimates and reservoir production data. However, in some instances, one curve may not be adequate to obtain a fit with historical data. In such cases, more than one curve is used. Hook (2009) argued that with an increasing number of fields involved and aggregated (such as the analysis for an entire nation or region), the error or peculiarity of an individual field becomes negligible. Hence, production decline curves are preferred models for forecasting future production profile for several fields aggregated together in a region if current production is already post peak for the region such as Nigerian onshore fields (Jakobsson, 2012; Munisteri & Umekwe, 2017).

As also noted by Poston & Poe (2008), decline curves being equations of lines fitted to match historical production data and extrapolated to future production, are relatively simple and easy to understand. Unlike other production forecast methods, decline curves require few input data. They require only historical production data which is easy to acquire at aggregate level for a nation or region. Fortunately, corporate bodies, such as British Petroleum, regularly publish production data at the national or regional level. Other natural resource management agencies in some countries and the World Bank also provide regular update on crude oil production rates for nations and regions. Production decline curve methods are also easily programmable, and time and cost efficient. On the other hand, in low permeability multi-layer reservoirs, they do not satisfy material balance equation and are challenging to fit into lines (Poston & Poe, 2008). This is attributed to the high variability and uncertainties in cross-flows in these types of reservoirs. Changes in operating conditions can easily affect the shape of the decline curve. As a result, their use in the prediction of future production is limited for low permeability multi-layer reservoirs. These reasons notwithstanding, in comparison to other predictive models or methods, decline curve is a simple method of predicting future production rates of oil fields. Therefore, DCA will be adopted to estimate future production rates and subsequently, size of rent in this study.

5.5.4. Production DCA and Suitability for Onshore Field in Nigeria

From the historical production profiles in Figure 18 and given that Nigerian onshore crude oil fields have been in operations for several decades and are already in the post peak production decline phase, it is easy to observe that they have gone past the transient stage. Production from the onshore wells are expected to have drainages that touch the reservoir boundaries. Crude oil production from onshore fields in Nigeria is already in the mature stage and has attained the peak. Depletion from onshore fields in Nigeria are now predominately driven by direct depletion mechanisms. At this stage of maturity, historical production data will provide a good representation for the interplay of physical reservoir factors and direct driven depletion mechanisms already occurring in the fields. Reserves estimation methods and production forecast that are based on reservoir properties and performance, such volumetric analysis, material balance calculations, and other computer modeling techniques, may demonstrate more rigors, but the level of details required is disproportionate for a macro-level policy planning objective, such as decommissioning of the onshore fields. Historical production data for most of the wells are held confidential. Fortunately, aggregate production for the entire region can be sourced from public database, such as the annual BP World Petroleum Survey and extant literatures. Therefore, DCA will be a good approach to production forecasting for long term policy purposes in Nigeria.

Decommissioning of oil and gas facilities in Nigeria can be classified as a common pool resource management problem and a public policy development issue. This supports the position that complex models are not compulsorily (Armstrong & Trevarthen, 1999; Bhattacharyya, 2011; Bhattacharyya & Timilsina, 2009; Green & Armstrong, 2015) and may not be appropriate for policy making for decommissioning of petroleum fields in a country with weak and evolving institutional frameworks, similar to Nigeria and other developing countries. The Hotelling and Hubbert's models are data intensive and require a suit of assumptions. To avoid limitations with lack of detailed information and data on crude oil production from Nigeria fields, and the associated assumptions that will be required to apply the Hotelling or Hubbert's models, this study will apply production decline curves analysis for crude oil production forecast, and estimation of rent sizes for different price and EOFL scenarios for Nigerian onshore crude oil fields. Based on the aforementioned reasons, exponential and harmonic DCA will be good assumptions and simple fit for the pessimistic and optimistic future production forecast for Nigerian onshore fields. For a high level public policy decision, the exponential and harmonic decline curves can be assumed to represent the pessimistic and optimistic production rate boundary conditions. However, to evaluate the confidence around results from deterministic analysis, hyperbolic decline curve production forecast can also be evaluated under a probabilistic analysis with an appropriate randomly varied value of b, the hyperbolic exponent (Beninger & Caldwell, 1991; Kamari et al., 2017).

5.6. Propositions for Adequacy of Simple Production Forecast Methodology for Decommissioning Policy Decisions

The first deduction from the literature review is that data on reserves depletion and production decline is required to evaluate the size of potential rent from petroleum resources and to match the rent with associated decommissioning liabilities. The results will support decommissioning policy development and planning efforts. It should not be acceptable to postpone proactive planning for decommissioning until the MOCs or other operators provide information on production and reserves forecast to public stakeholders in a region. There may be adequate information already in public space. In addition, waiting until the fields become clearly uneconomical to operate and are abandoned before kick starting a plan for decommissioning may be too late.

The second deduction from this literature review is that complex production and reserve data, and data intensive analysis are not compulsory for a sustainable decommissioning policy to be developed and implemented. A decommissioning policy is an over-arching high level decision, particularly for a region or country. Policies formulation and implementation do not require granular data if cursory data can provide the same inference or trend. For a decommissioning policy to be in place, production trend and reserve trend data are necessary to show the imminent concerns and need for action. However, they do not need to be granular. A simple reserve and production model with transparency will be adequate. The data must not be complex or very granular, particularly for a region or country. It only needs to be accurate, consistent, and transparent. Simple data and models, such as trend analysis, can provide information that is good enough for policy making (Patton et al., 2016). This information must also be available in the public space. Policy formulation and management can make do with data that can be consistently generated, fairly accurate, and transparent. In the case of Nigerian onshore fields, it demands simple trend information on crude oil production and reserve that is representative of the dominating natural phenomenon that is driving depletion of the reservoirs.

Furthermore, this information at an aggregate level is accessible. Therefore, a delay in the development of a good decommissioning policy cannot be excused based on lack of reserve data. We can conclude that availability of reserve and production data on a consistent, accurate, and transparent basis is therefore a critical but achievable criterion for a good decommissioning policy.

6. Decommissioning and Associated Petroleum Fiscal Policy Challenges

One follow-up issue that arises from having a consistent and comprehensive cost estimate for decommissioning liabilities is the appropriation of accountability for the liabilities and designation of the party responsible for payment for decommissioning activities. For companies and investors (including the government), it is one more undesirable deduction from the revenues accrued from the natural resource. It takes away from the funds that could be reinvested in the development of other natural resources or shared as profit. However, for the government, it is also a liability that must not be orphaned, else the government will bear the burden alone. Therefore, governments must find optimal and creative ways to manage the balance between ring-fence of funds for decommissioning liabilities and release of funds to investors.

6.1. Petroleum Fiscal Policy

A fiscal policy refers to the process and associated systems or structures through which the government collects or manages revenues and indirectly influences economic growth in a desired direction. According to Friedman (2001), it establishes a relationship between government expenditure and taxation or other sources of funding for government expenditure, such as royalties, fees, and debts. Higgins (1992) described fiscal aspects as "those mechanisms which directly affect the amount and timing of a government's and company's share of revenue generated by a project," which in this case is a petroleum investment project. Therefore, a petroleum fiscal policy would refer to the process and associated systems or structures through which the government collects or manages revenues from its petroleum industry and indirectly influences economic growth of the industry. Gudmestad et al. (2010) noted that a "petroleum fiscal regime refers to a set of laws, regulations, and agreements which govern the economic benefits derived from petroleum exploration and production. It regulates transactions between political entities and legal entities" involved in the petroleum industry. It is important to note that the petroleum licensing system is different from the petroleum fiscal regime or system (Figure 33). Even though the former is a precursor to the latter, they are distinct. The licensing regime is focused on the processes and methods of granting petroleum exploration and production rights to prospective investors while the fiscal regimes seek ways to collect rents and taxes from petroleum resources, and to spend them.

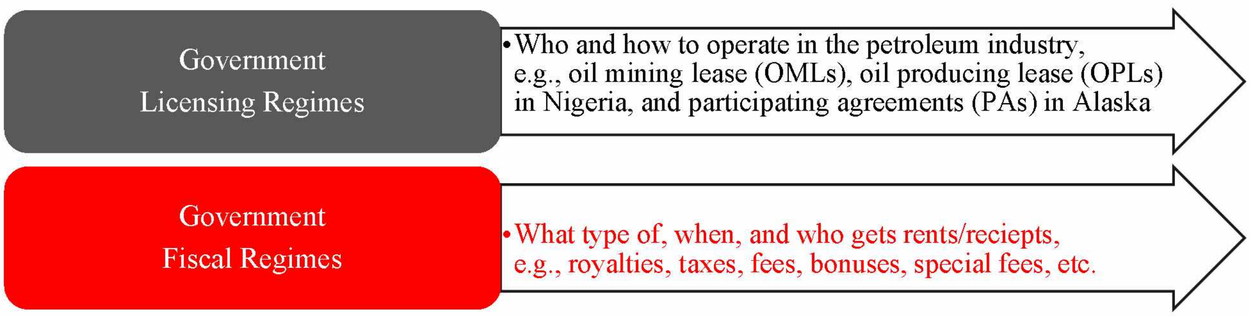


Figure 33: Petroleum licensing and fiscal regimes

Tordo (2007) considers fiscal regimes as more of legal arrangements that have fiscal terms, particularly in places where comprehensive hydrocarbon laws do not exist. In those places, it is also the operational guide to business/commercial relationships. The agreements and associated fiscal elements are the instruments used by government to implement its petroleum policies. Therefore, "E&P contracts and the associated fiscal regimes may be of several types depending on the legal system used in the country and its selected petroleum policy" (Le Leuch, 2013). The fiscal provisions determine the overall portion from the petroleum revenue that goes to the government, whether as taxes, fees, or some other economic and non-fiscal terms in the contract. The percentage of the revenue from petroleum that comes to the government, which integrates all the streams of income either cash or kind, is described as the government take (GT). This is an important measure in any petroleum fiscal regime.

6.2. Types of Fiscal Systems, Regimes, or Agreements

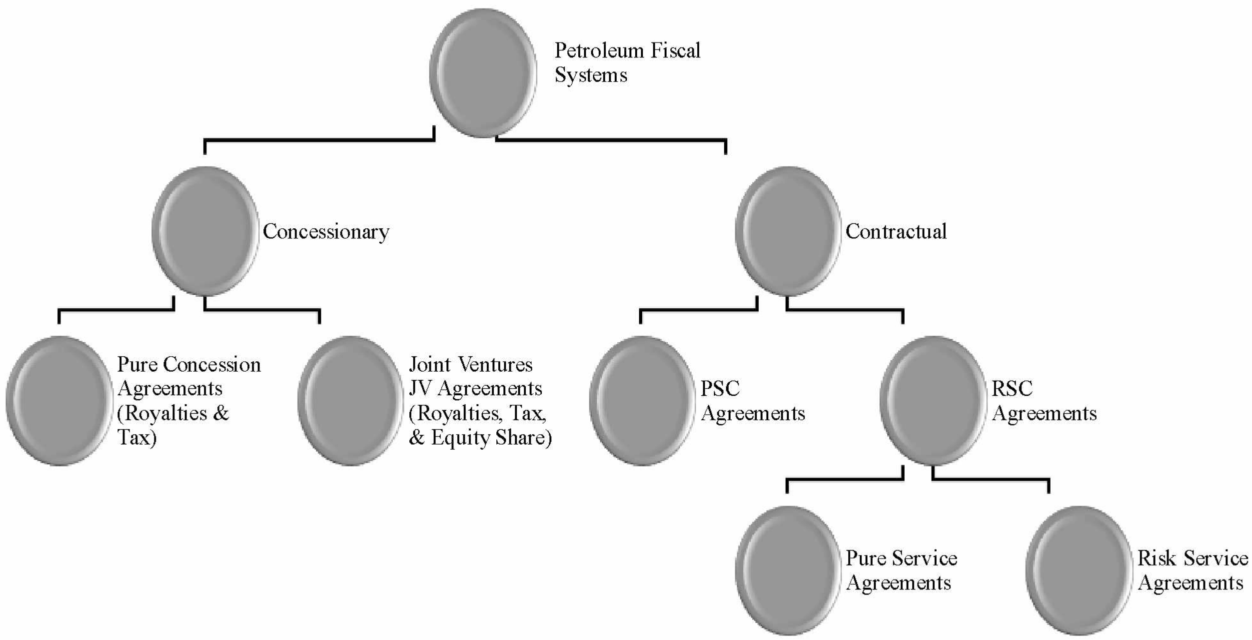


Figure 34: Petroleum fiscal systems

There are two main types of petroleum fiscal systems or categories – concession and contractual fiscal systems (Figure 34). Coddou et al. (2012) identified three categories, royalty/tax, production sharing, and service agreement, but went further to collapse them under two major categories, concessionary fiscal system and contractual fiscal system. Contractual fiscal system collectively describes production sharing and service agreements. Chukwu & Ikoku (1991) and Mmakwe & Ajienka (2009) also identified two similar categories, concessionary fiscal system and contractual fiscal system or agreements. Le Leuch (2013) noted that the main difference between the main types of agreements is in the tax obligations and percentage of extracted production that is assigned to the investor or contract holder, or owners of the mineral resource.

6.2.1. Concessionary Fiscal System or Agreement (JV Agreements)

Under the concessionary agreement and fiscal system, the government grants exclusive exploratory and production rights for oil and gas mineral to the investors in a designated area or acreage. The investor holds total ownership rights to the mineral resource once extracted to the surface or designated point. The investor can only lay claim to the petroleum resource after it has been extracted to the surface or other designated point. While the petroleum resource is still in the ground, it belongs to the government or land owner. The government does not contribute any fund toward the E&P activities. The investor bears all the risk and cost involved in exploring and bringing the petroleum resource to the well head or agreed fiscal metering point. However, the government collects severance tax or royalties and several other forms of taxes from the investor once production starts. Therefore, the investor owns 100% of the extracted petroleum resource at the surface or designated point, and pays royalties and other taxes to the government. This type of agreement does not offer the government flexibility in accessing revenue from the resources. For example, in the scenario of high oil prices, the percentage of government revenue will remain the same as in the time of low oil prices. In the event of a profit windfall, the absolute revenue that comes to the government will not be comparable to the money made by the investor.

In recent times, these terms have been modified to what is described as modern concessionary agreement and fiscal system. In some modern concessionary fiscal structures, there is a sliding royalty scheme where the royalty percentage is flexible and can be adjusted based on the volume of production or even price. In some countries, the government uses a national oil company to receive some percentage of equity participation in the investment. Leveraging its equity, the government obtains additional benefits from the petroleum resource. This is described as government carried. Due to this reason, Higgins (1992) considers that there is no true concession any longer after 1950s, but rather royalty/tax agreements and fiscal systems. A strict concessionary fiscal system according to Higgins, should have a fixed royalty rate and one-off signature bonus. However, modern concessionary agreements have sliding royalty rates and multiple quasi-fiscal terms. This was supported by Mmakwe & Ajienka (2009) description of JV agreement structure as a type of concessionary agreement where there is a royalty element, but with government also participating in the equity. Under a JV agreement, the government is supposed to foot the cost of exploration, development and decommissioning, to some agreed percentage. Almost all onshore fields in Nigeria, which are the focus of this study, are operated under a JV concessionary fiscal system.

6.2.2. Contractual Fiscal Systems or Agreements

Contractual agreement and fiscal systems may be PSC or risk service contracts. Mmakwe & Ajienka described PSC and RSC agreements as basically sub-categories of contractual fiscal system or agreements, but with differences in the method used by the government to make payments for the service fee. Payments under PSCs are made in kind, while under RSC, they are paid in cash.

6.2.2.1. Contractual Fiscal System – Production Sharing Contract (PSC)

A production sharing contract (PSC) and fiscal system is an arrangement where the investors or companies and the government agree to share the risk, and hence profit from a petroleum investment according to predetermined ratio and terms. The government retains ownership of the resource at all times, except at the point when it relinquishes a volume in kind as a payment for the cost of operation to the investor. The government shares the risk with the investor and when production starts, the government also shares the profit with the investor at the predetermined percentage. Under this agreement, the government does not foot any cost of exploration and development until production kicks-off. The investor is paid back the cost of production or agreed cost in kind as soon as production starts. However, the investor does not have any right to the extracted mineral at any time, except the quantities used to pay for its services. The development and production cost may not be recovered at once, but phased over a period and up to an agreed limit in a particular year. As a result, in most cases, the investor may not be able to recover all the cost of development and production within a year. A CIT may be paid by the national oil company or the investor depending on the terms of the agreement. The investor is also subjected to other imposed taxes and fees as under the concessionary agreement.

6.2.2.2. Contractual Fiscal System – Risk Service Contract (RSC)

Under a risk service contract (RSC) and fiscal system agreement, an investor is hired by the government to manage the petroleum resource at a pre-agreed fee described as the service fee. In some cases, the government provides funds for the development and production, while in other cases, the contractor or contract holder provides the fund and assumes all the risk. The investor is paid in cash for all services rendered at agreed terms. The investor does not have any access to the extracted crude oil. It is the least popular of all the three methods – JV, PSC, and RSC agreements. The service fee is still subject to CIT. Mmakwe and Ajienka (2009) went further to break RSC agreements into two sub-categories, pure service and risk service contracts, where the differences are in the method of cost recovery from the government. Under pure service contract, the investor is paid a fixed fee for managing and executing the field development even if crude oil is not found in commercial quantity. In a risk service contract, the investor takes all the risk and is paid only if crude oil reserves are found and produced.

6.3. Terms, Tools, and Elements of Petroleum Fiscal System

While some agreements may offer the government more flexibility to access revenue from the resource, the fiscal elements and most of the tools with which the government access the revenue, cut across all types of agreements or contracts and only differ in specific applications.

There are several reasons or drivers behind the selection of terms and elements into a petroleum fiscal regime. First is the fact that petroleum is a finite non-renewable resource. Its depletion means an alternative forgone forever. As such, the opportunity cost needs to be appropriately paid for or rewarded. Second is the high level of front-end capital investment required for a petroleum development project. Relatively, it takes a longer time for an investment in a petroleum resource to begin to generate cash inflow or break-even. Third are the several inherent risks, such as geological, political, and technical risks associated with a petroleum investment. Fourth is the domineering nature of revenues from petroleum relative to other sources of revenue that come to the government. A local economy can be easily and quickly heated up with revenue from petroleum, only to dry up unexpectedly at EOFL and leave behind an unsatisfied crave for high government spending.

The objective of a good fiscal regime is to competently address these issues. Baunsgaard et al. (2012) identified the elements of a good fiscal policy framework to include "(i) indicators to assess the fiscal stance; (ii) a benchmark for assessing long term fiscal sustainability; (iii) a rule that anchors the short- to medium-term fiscal policy paths; and (iv) the requisite institutional setup, such as the capacity to undertake long term revenue forecasts and accord a medium-term orientation to the fiscal framework."

A government in setting and managing a fiscal regime, seeks to find a balance between encouraging investment from investors and getting a large and quick reward or rent from the petroleum resource into government coffers. However, experience has shown that it is not a large and quick reward, but sustainable reward that should be the focus of a government fiscal policy. Fiscal regimes and terms should be clear and without ambiguity, should be stable, predictable, and not susceptible to unanticipated changes (Nakhle, 2008; Shimutwikeni, 2011). They should align with anticipated cash flow from the investment such that revenues do not lag behind the public's rational expectations of income from the resource. Tordo (2007) observed that a fiscal regime for oil and gas has to be flexible, which means that it should continue to provide government equitable resource, neutral by neither encouraging over-investment nor discouraging investments, and stable in the face of economic and political uncertainties. Baunsgaard et al. (2012, p6) also stated that "fiscal policies should ensure macro-fiscal stability; fiscal sustainability for countries with temporary resource revenue flows; scaling up growth-enhancing expenditure, which may need to be gradual if absorption and institutional capacity constraints are large; and adequate accumulation of precautionary savings."

While a sovereign government can decree and abrogate the terms and conditions of a contract, stability and predictability is almost sina-qua-non for a thriving petroleum industry. The huge geological and capital investment risk associated with petroleum resource development does not allow the industry to tolerate any other uncertainty. Therefore, governments seek to use different tools or fiscal instruments to manage the fiscal regimes in ways that suggest stability and predictability. The instruments most commonly used are royalties, bonuses, and taxes, which may have variations, such as sliding royalties, ring-fencing, loss carry forward, stabilization, windfall or petroleum profit tax, government participation in equity or government carry, and sundry fees.

6.3.1. Classification of Fiscal Instruments

Agalliu (2011) studied 29 petroleum fiscal systems globally and concluded that fiscal instrument can be broadly categorized as ad valorem or production-based levies, profit-based levies, equity participation, and quasi-fiscal instrument. Ad valorem or production based levies include royalties, severance tax, and export duty. Profit-based levies include income tax, petroleum profit, windfall taxes, and profit sharing. Equity participation includes government mandatory equity participation in a project after production starts, which is also termed as government carry. Quasi-fiscal instrument also described by Tordo (2007) as non-tax instruments, include bonuses, rentals, and training or research fees. Otto & Cordes (2002) categorized fiscal instruments as either direct, indirect, or quasi-direct taxes, to which some authors add a fourth category, special instrument taxes. Tordo classified fiscal instruments into tax and non-tax instruments (Table 7). Tax instruments include royalties, ring fencing tax terms, corporate income tax, resource rent tax, petroleum profit or windfall tax, import and export duties, value added tax, and surface taxes. Non-tax instruments include bonuses, government participation in profit sharing, cost recovery limits, performance bonds, and environmental bonds.

Table 7: Taxes and E&P fiscal system

Tax Instruments	Non-Tax Instruments
Royalties, Ring Fencing Tax terms, Corporate Income Tax, Resource Rent Tax, Petroleum Profit Tax PPT or Petroleum Windfall Tax, Import and Export Duties, Value Added Tax VAT, and Surface Tax	Bonuses, Government Profit Split, Cost Recovery Limits, Performance Bonds, and Environmental Bonds

6.3.1.1. Front-loaded or Back-loaded Fiscal Regimes

Fiscal regimes may also be viewed from the perspective of time along the project lifecycle, when the government receives its revenue or most of its revenue from the petroleum field development project. If the government seeks to collects much of its rent upfront before productions starts or at an early stage, the fiscal regime is front-loaded. On the other hand, when the government delays rent collection until much later in the life of the investment, then it is back-end loaded. Investors do not prefer front-loaded fiscal regimes as they are made to part with cash inflow when the investment is yet to satisfactorily generate positive cash flow. Governments prefer front-loaded fiscal regimes as they satisfy the appetite of the public for immediate rewards from the resource.

6.3.1.2. Progressive or Regressive Fiscal Regimes

A fiscal regime may also be described as progressive or regressive. It is termed as a progressive fiscal regime if the fiscal instruments operate in such a manner that the GT as a percentage of total revenue from the petroleum resource increases with increase in production or price of crude oil or profit. On the contrary, it is regressive if the GT decreases as the production or price of crude oil or profit increases.

6.4. Government Take (GT) and Decommissioning

The GT is not only considered as the total rent from the petroleum resource coming into government coffers, but a common heritage whose management, size, and timing attracts huge political capital. Any factor that affects it is not glossed over by the public. From a perspective of how it is determined, we can summarize or describe GT as a combination of three strings or elements of resource rents. First is the royalties or production based rent elements, which are mostly pre-tax. Second is the profit based rent elements, which are post-expenses and mainly taxes, and third are the other service fee and rent elements, such as bonuses, bond fees, and special fees.

Royalty or other production based fiscal entitlements are first removed from the petroleum revenue before any other expense element is recognized. Apart from efficiencies that result in an increase in volume produced, royalties are not directly affected by operational and financial efficiencies of the company. It is not related to expense or capital funds. It is charged before expense and taxes are removed.

Service fees and rent elements, such as bonuses and research fees, may also not be directly related to operational or financial efficiency. For example, research or training fees or sign up bonus fees are not related to operational efficiencies.

Profit-based rents are the only elements that are directly related to operational and financial efficiencies. The amount of capital and operational expenditure can affect the amount of profit available for taxation. To calculate this element, the capital expenditure, as allowed in the agreements, and operating expenditures are deducted from remaining revenue after taking away the royalty. For PSCs, this may come in terms of cost oil. These deductible cost elements are most often not very transparent to stakeholders outside the operating company, such as the Nigerian public. The items included are the normal operational expenses, drilling expenses, salaries and overheads, and allowances for depreciation and decommissioning. Therefore, the GT is influenced by the efficiency of the operations and accounting transactions of the oil company. The less the expenditure deducted before arriving at taxable profit, the better for the government. The cost of abandonment and decommissioning is one of the deductible cost elements. For example, in the year a decommissioning activity is completed, the cost may be completely expensed. A large cost for abandonment and decommissioning can wipe away the taxable income and lead to no fund accruing to the government.

6.4.1. Decommissioning and Abandonment in Fiscal Regimes

Decommissioning and abandonment is treated in several ways in different fiscal regimes and is important to the economics of a petroleum investment. According to Antia (1990), the economics of a field abandonment is dependent on the way abandonment cost is treated in the fiscal policy or regime, the terms of tax relief for abandonment, and the actual cost of abandonment. The UN Committee of Experts on International Cooperation in Tax Matters identified provisions in taxation framework for the allocation of funds for decommissioning to be either through (i) unit of production method, (ii) amortization over field life, (iii) carryback against taxation, or (iv) grant system and tax deductible on the fund and growth of the fund (United Nations, 2014). Pittard (1997) consolidated the fiscal provisions for abandonment into four types – carryback, amortization over a field life, amortization based on unit of production, and expensed. Pittard (1997) provided a detailed description of each type, but from an investor's perspective. The expensed approach to decommissioning cost is preferred as investors will not part with money for decommissioning until sometime in the future when it is actually executed. It pushes the capital expenditure on decommissioning further away, which improves the net present value (NPV) of the field development, hence encouraging the amphoteric "wish-it-away" attitude toward decommissioning liabilities. Muehlenbachs (2015), from a dynamic discrete choice model, identified that investors are using temporary closure to delay and avoid environmental remediation of abandoned facilities. There is an economic incentive to push the actual incurring of the cost further away and provide more cash flow benefits to the investor at the moment. Therefore, the social cost of production is not timely appropriated leading to inter-temporal inequity. The total cost of production includes the direct cost of production paid by the oil company (i.e., private cost of production) and the cost of the unabated negative impact of the production system on society, such as environmental pollution resulting from improperly decommissioned facilities (i.e., social cost of production). The generation currently enjoying the benefits of the crude oil production may not be available to pay for the decommissioning, effectively leaving some of the social cost of production for the future generations to pay. This will be an intergenerational inequity.

On the other hand, the investor may also not wait until the end to economic life of a field to decommission the asset. The investor may want to have cash inflow against which to charge the decommissioning expense. This could lead to premature decommissioning. Again, this may be a loss of revenue to a future generation and a sub-optimal inter-temporal decision.

Contrary to private investors, the government and public will prefer decommissioning cost, which is a liability, to be totally borne by the investor. At the extreme, government will prefer the investor to make down payment for decommissioning liability even before production commences. The government will also seek for the decommissioning to take place only after all the recoverable volume of oil has been extracted. A government policy will seek to discourage premature decommissioning, which operators may want to do for the purpose of obtaining positive cash flow against which decommissioning expense can be netted off. This is where the carry back provision in the fiscal policy could be helpful. This is a popular feature provided for decommissioning in most fiscal systems.

6.5. Financial Assurance for Decommissioning Liabilities

To mitigate the risk of oil companies default in meeting decommissioning obligations, governments adopt bond and other financial assurance instruments to guarantee that decommissioning liabilities will not be left unsettled by the investors. Governments also want to simultaneously ensure that cash flow benefits exist to encourage continued development and investment in a petroleum resource. The optimal objective of a financial assurance instrument is that the investor does not currently restrict too much fund (for example, by making down payment) for decommissioning that could otherwise be invested in other profit yielding activities. However, simultaneously, it still provides sufficient guarantee (for example letter of credit) that decommissioning liabilities will be paid for by the operator when it occurs. Financial assurance instruments are used to ensure that future generations are neither exposed to unnecessary or disproportioned cost burden for decommissioning, nor shortchanged by premature decommissioning that leaves stranded and uneconomic assets in the reservoir. According to the United Nations (2014), financial assurance instruments include current cash flow from existing operations, parent company guarantee, bank guarantee, letter of credit, insurance guarantee, decommissioning/removal fund, and ring-fencing of decommissioning funds.

Financial assurance tools are treated differently in the fiscal regime. A financial assurance tool selected by a government will ultimately be aimed at achieving the government fiscal objective, which in most cases seeks to increase or at least sustain GT. Therefore, in simple terms, other reasons not over-riding, the government will choose the financial assurance tool that least reduces GT.

6.5.1. Financial Assurance – Bonds and Bond Setting Mechanism

Ferreira & Suslick (2000), considering decommissioning from an environmental liability and externality perspective, described bonding as one of the market-based and economic incentive approaches to regulate environmental liabilities and internalize externalities, such as decommissioning liabilities. The operating company in making regular payments to the bank or financial institutions to maintain the bond for its decommissioning liabilities is encouraged to consider the cost of decommissioning liabilities in its total production cost. In this manner, the cost of decommissioning liabilities is internalized without the government issuing a command for it to be captured. If the size of liabilities is too high for the operator to profitably maintain its decommissioning bonds, it will be constrained to either complete decommissioning for some of its facilities, so as to reduce the total cost of decommissioning liabilities or slow down on its business expansion. Without the government's control on expansion, the operators are not incentivized to internalize the cost of decommissioning liabilities and will have a free ride on a cheaper production cost.

Ferrira and Suslick (2000) surmised from empirical studies that the other type of regulatory approach to environmental liabilities, which is command and control, is not efficient as it is not only very expensive for a government to gather data and monitor compliance to a prescriptive regulatory command, but it does not encourage the private sector to innovate for a better solution to the environmental problem. Moreover, companies can escape payment for their liabilities by declaring bankruptcy, leaving the liabilities for the government to bear the cost if they realize it is a cheaper route. In contrast, bonding, similar to other economic incentive instruments, will encourage all stakeholders to share in the responsibility to manage the environmental liabilities. The regulatory body can also use the economic incentives to encourage a pattern of behaviors. With demand for financial assurance bonds, oil and gas companies are incentivized to comply with their decommissioning and abandonment obligation or ARO as a good track record of managing their ARO will positively affect their corporate reputation, insurance risk, and premiums they pay. It also provides guarantees to the government that payment for the liabilities will not be left for the government and public to bear.

6.5.2. Type of Bond Arrangement for Decommissioning Liabilities

According to Cornwell & Constanza (1994), the bonding system requires economic agents to post a bond equal to the worst-case damage they may cause to the environment, before they begin to utilize a common pool resource. For the oil and gas industry, Ferreira & Suslick (2000) defined bonding requirements to include expectation for a company to post a bond that could cover the total cost of completing abandonment and decommissioning of the facilities it will install. It is expected to be posted ahead of any E&P activity. There are several types of financial bond instruments even though the two basic types are performance and cash bonds (Ferreira & Suslick, 2000).

Performance bonds: They are used to guarantee that a company will satisfactorily meet its decommissioning liabilities else the bond issuer will pay for the full liability. Surety bonds which are performance bonds are similar to liability insurance protection. An oil company will purchase a surety bond from a bank or an issuing agency to the extent of the amount that covers its decommissioning liability. The company does not have to make a cash deposit to the tune of the decommissioning liability. It will only make annual premium payment as will be determined by the surety bond issuer. The premium will, to a large extent, be determined by the track record of the level of compliance by the oil company and its probability to default. This bond arrangement can also help incentive an operator to meet their decommissioning obligations incrementally as they fall due and to also be environmentally compliant. As a performance based instrument, it incentivizes the company to proactively and incrementally meet its decommissioning liability consistently else the premium it will pay for the bond issuer to provide the bond coverage will be higher. An environmental reputation damage can lead to higher premium or even the financial institution refusing to issue a bond for the oil company. By paying for bonds and incrementally completing decommissioning of some of the facilities and remediation of some sites, the oil company internalizes the cost of decommissioning and abandonment. As a benefit, if the company fails to perform its decommissioning obligation and it is unreachable for any reason, the government and regulatory body are assured that decommissioning will be effected to the agreed standard as the bond will be called and used to pay for the proper decommissioning of the abandoned fields.

Cash collateral bond: With this bond, the oil company deposits a cash amount about or over the established cost of meeting the decommissioning liability, in an escrow account with a safe bank. The government regulatory body will have full control over the account until the liability is fully met and the bond released. Any interest earned on the deposited amount may be withdrawn annually provided the value of the bond can still adequately cover the ARO liabilities. The company will not have access to the deposited money for decommissioning. It is still expected to look for funds to complete decommissioning according to pre-determined standards, after which the government can release the cash collateral bond back to the operator.

Periodic-payment cash collateral or pay-as-you-go: The oil company makes periodic payments to meet the full decommissioning liability cost within an agreed period. There can be several variations to this type of bond. The trust bank account can be managed by the regulatory agency without any interest payment on the money or may be managed similar to a cash collateral bond with interest payment made to the oil company on an annual basis. All the funds are held until the decommissioning liability or ARO is satisfied.

6.5.3. Other Exotic Forms of Guarantees and Bond Arrangements

6.5.3.1. Decommissioning Deed

In the UK, the government has developed a form of covenant agreement described as decommissioning deed between operators on the one hand and the government on the other hand. Operators contribute funds toward a decommissioning assurance trust fund bond. The government is positioned to execute the bonds in the event of a failure by the operator. It is in some ways similar to an orphan wells fund in Alberta, Canada, except that instead of providing funds for decommissioning of an orphan well, it provides funds for a decommissioning surety bond against an event of improper decommissioning of a well or facility by the operators.

6.5.3.2. Bonding Arrangement in the Outer Continental Shelf (OCS), United States

Another variation in the implementation objective and mechanism to surety bond is the supplemental bond as administered by the BOEM in the Outer Continental Shelf (OCS) of the United States. BOEM demands from every operator a general bond covering all risks from all activities of the oil company in a field. The amount covered by the general bond depends on the size of operation and potential rent, royalties, and other operational liabilities that may be associated with operations in the lease. However, events related to negligence like spills, are not covered under the general bond. According to Kaiser & Kruse (2011), supplemental bonds are required to cover obligations, including decommissioning obligations that exceed the amount covered by the general bond. Most part of these extraneous liabilities arises from decommissioning activities. Therefore, the bureau of ocean energy management (BOEM) requires a diligent estimation of the decommissioning scope to avoid missing out any element of the scope, which could then result in becoming a burden to the government and the public.

6.5.3.3. Bonding Arrangement in the Cook Inlet Alaska, United States

At times, regulatory bodies use a combination of financial bond instruments. For example, Van Dyke & Zobrist (2001) identified the unique approach used in the state of Alaska to ensure a financial assurance for ARO during the sale of Middle Ground Shoal Field in Cook Inlet fields in Alaska to a mid-size independent oil and gas company. The state set up a site-specific abandonment funding agreement, which used a combination of surety bond, escrow account, and collateral provided by value of proved reserves as means of financial assurance for the ARO at Middle Ground Shoal Field, Cook Inlet Alaska. The agreement entails a $3 million annual renewed surety bond intended to generate immediate cash flow for maintenance and operation of the offshore platforms in the event of bankruptcy or default by the lease. The second element in the funding agreement is the proved reserves, the lessee will submit the proved reserves status on an annual basis. Based on the volumes of proved reserve, selected price of crude oil, cost of operation, and discount factor, the value of the proven reserves is determined and used to assess government exposure to ARO in the event of a default. The third element, an escrow funds account managed independently from the lease, is used to receive payments from the operator toward decommissioning of the lessee's oil and gas platforms. Payment will be made into the fund, if it is determined that the NPV of the proven reserves is less than the 150%

of the NPV of the sum of the estimated ARO and any money already deposited into the fund. The difference is required to be paid into the escrow account by the lessee.

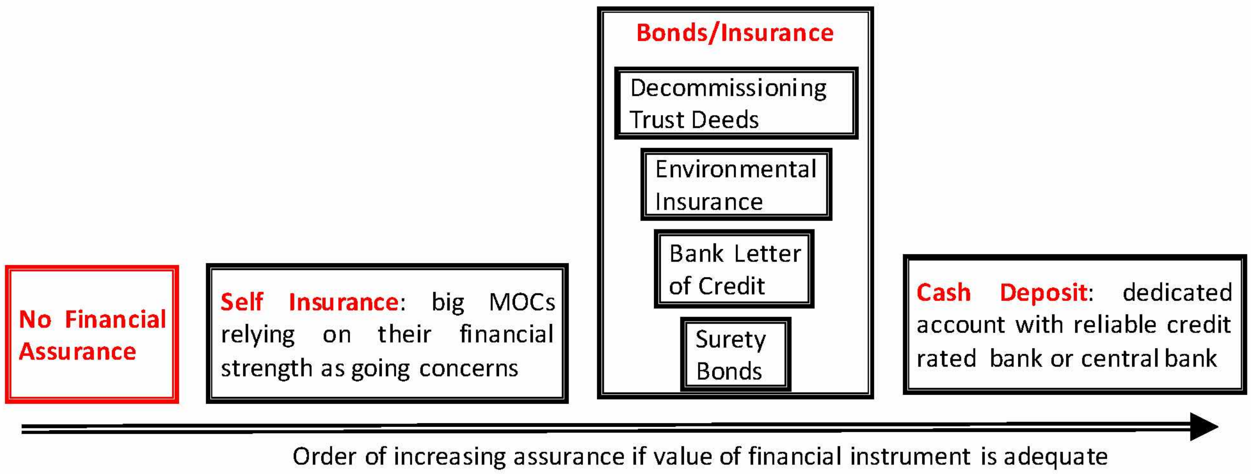


Figure 35: Financial assurance instrument – Assurance and confidence levels

There appears to be as many methods of financial assurance as petroleum producing countries. However, in developing nations, the financial assurance mechanism for decommissioning risk is often not well defined. There is limited interest on how it is implemented and limited or no experience on how to implement it. For example, the decommissioning of Ogoni fields in Nigeria that has been decided upon for over a decade is yet to be completed by the oil company (Osibanjo, 2017; United Nations Environmental Programme, 2011). Yet, the government has not for once indicated that if frustrated by the oil company, it could call on any bond or financial instruments earlier provided by the operator to complete the decommissioning. Instead, there are national and international efforts, to convince the operator to set up a restoration fund that did not previously exist for decommissioning of Ogoni fields. This may as well be an indicator that there was no financial assurance provided earlier in the field development plan against a decommissioning default risk for the Ogoni fields.

Bonding or other forms of financial assurances for petroleum field decommissioning liabilities have to be in the petroleum fiscal system to ensure that the government and public are not left to bear the burden of decommissioning alone (Figure 35). Considering the competing objective of maximizing revenue to the government, the effect of any financial bond arrangement on GT has to be evaluated and acceptable for a decommissioning policy to be sustainable. The World Bank's study highlighted the presence of financial assurance elements as an important feature of a sustainable decommissioning policy (World Bank, 2010).

Financial assurance instruments, whether performance or cash bonds, do not necessarily and always translate to a fact and certainty that decommissioning will be properly done or not left for the government to pay for. The higher objective is for operators to be disciplined, altruistic and incentivized to properly complete decommissioning as part of their normal business operations. With this objective, the remaining crude oil that will be produced and accruing revenue becomes the most reliable factor that can be used to manage and incentivize operators to choose proper decommissioning. Therefore, the trend of remaining crude oil reserve is an important indicator in the management of decommissioning because unregulated and unmonitored, an operator can irresponsibly dissolve the company abruptly and elope or decently declare bankruptcy. "Dissolution can be a rational, [even] if socially irresponsible, way to avoid future challenges" (Boyd & Ingberman, 2003). Furthermore, since the government will ultimately bear the burden if operators fail to properly complete decommissioning of the fields, the remaining crude oil reserves become the most important assurance against decommissioning risk. For the government, the details of assurance from the revenue can be further driven down to the particular stream of revenue that will be most readily available to use to pay for the decommissioning liabilities left behind by an operator. For a fiscal system with tax rebates for decommissioning, the remaining stream of revenue may also be used to provide tax break incentives to operators after successfully completing decommissioning of the fields. The entire value of revenue from the resource may not be available to address decommissioning liabilities. Therefore, it is important to determine the adequacy of different revenue streams to pay for decommissioning liabilities. Among all the different revenue streams, tax is the most reliable that can be used to pay for decommissioning liabilities. Tax is also the part of revenue that the current generation managing the resource can lay claim to. Hence, vulnerability in terms of tax revenue is a significant indicator of vulnerability to decommissioning risk.

6.6. Proposition – Remaining Revenue Streams as Assurance Against Decommissioning Obligations Default Risk

This study holds that a sustainable decommissioning policy for onshore fields should have appropriate financial assurance and bonding elements against the potential risk of abandoned decommissioning liabilities.

The cash or performance bond is supposed to provide financial assurance against decommissioning default risk. However, the collateral factor behind the bond is the value of the remaining crude oil reserves. Therefore, the foundational assurance comes from the value of the remaining crude oil reserves. Depending on the value, vulnerability to a default risk event is therefore dependent on the behavior of the value of the reserves. Vulnerability will increase with a decrease in the value of the reserve. The remaining revenue is dependent on the price of crude oil, but also on the disposable revenue that the government can actually get and make available to pay for decommissioning. The entire revenue may not be available to make payment for decommissioning, even if the government takes possession and operates the asset. Essentially, it may even be less as a government is not the best operator of a commercial venture. There are uncertainties around the value of remaining reserves which creates some risk around the revenues and coverage it provides. The price of crude oil, volume of resource, tax rate, and cost of decommissioning also have uncertainties. Even though decommissioning must occur, the timing of its occurrence is also uncertain. However, among all these, the tax rate is the element that is within the control of the government and out of all the streams of revenues available to the government, tax revenue will be the most accessible and reliable to use for decommissioning. Therefore, while this study will evaluate vulnerability to decommissioning default risk based on the respective revenue streams accruable to the government, sensitivity and particular focus will be placed on the remaining tax revenue stream.

7. Decommissioning Obligations Default Risk and Policy Frameworks: The Measurement, Evaluation, and Benchmarking Challenges

The decommissioning phase in the petroleum and natural resource industries is fraught with financial, environmental, socioeconomic, and political risks, which can be huge, complex, and protracted. The susceptibility or vulnerability to the risk elements need to be quantified or defined so that the risk can be better evaluated and monitored as part of the risk management approach. Owen (2006) identified monitoring as a risk mitigation approach. Continuous evaluation and benchmarking of the performance of public policies or programs has also been identified as a necessary requirement for success in public policy implementation. Therefore, a methodology to quantify or measure vulnerability to risk of operators defaulting in meeting their decommissioning obligations and benchmarking of existing sustainable decommissioning frameworks for the purpose of gap analysis and continuous improvement of a country's decommissioning policy frameworks is very important.

7.1. Vulnerability to Decommissioning Default Risk

The fact that crude oil production could decline to an uneconomic level and that the society could run out of energy and associated economic sustenance from crude oil supports the need to have reliable crude oil production forecast. The human society, motivated by existential threat, may find alternative energy sources and associated life style. The petroleum industry's social footprint may be replaced by alternative life styles, but the expansive environmental footprint may not be easy to undo. The human society needs to proactively plan for decommissioning and environmental restoration of crude oil fields. While economists, such as Pindyck (2000; 2007) suggest that environmental regulations and environmental planning for future pollution events may not be necessary due to irreversible sunk costs, industry experience and sound public policy suggest appropriate planning and at a time "when the remaining hydrocarbon value equals the estimated decommissioning costs" (Thornton, 2017).

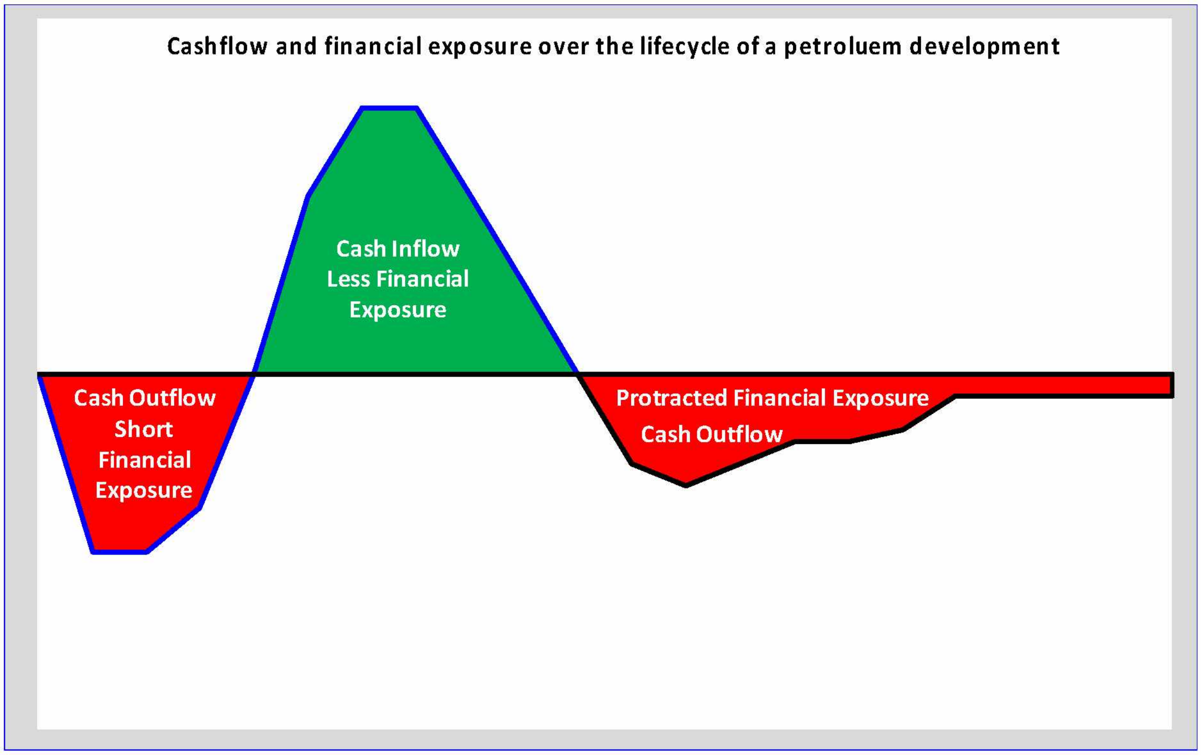


Figure 36: Petroleum field lifecycle cash flow and financial exposure

From a cash flow perspective, the life cycle of a typical crude oil development program can be described in three stages (Figures 8 and 36). The first and last stages are cash outflow dominant, while the middle stage is cash inflow dominant. The first stage encompasses exploration, seismic, appraisal, and field development planning phases. During this stage, funds are expended on discovery, engineering, and construction activities in readiness for production. Cash outflow at this stage is incentivized by anticipated income from the petroleum resources. In the middle stage, which covers the production phase, crude oil is produced, processed, and sold.

The revenues realized in this stage are usually more than the expenses incurred to produce the petroleum resource. The ongoing and expected income from the middle stage incentivizes the high stakeholder commitment normally observed in the production phase. The last stage, which is also cash outflow dominant, covers the decommissioning and abandonment phase. During this stage, revenues realized are less than the expenses incurred and there is limited expectation for a future production windfall, making economic-interest stakeholders less interested in this phase (IHS Markit, 2016; Judah, 2017). Consequently, there is a high likelihood of activities in this phase being left poorly completed. Therefore, the burden of these activities could be abandoned for not just the government and taxpaying public to bear, but also for future generations who are not stakeholders in the administration of today's tax revenue from the petroleum resource. Hence, decommissioning can be viewed as a business, and environmental and social obligation that is quantified in terms of the cost of decommissioning liabilities. Quantifying the cost of decommissioning liabilities and the remaining revenue from crude oil production throws up the concern about who will pay and how to pay for the cost of decommissioning liabilities. This makes decommissioning a financial risk to investors and a fiscal policy risk to the government and society, particularly given that whether managed under a private or public ownership rights regime, if the fields are not properly abandoned, a socially responsible government will have to bear the cost of proper decommissioning. The propensity is particularly more in developing countries, such as Nigeria without mature institutional and regulatory frameworks.

For the government and public, there are concerns about the likelihood of an operator's default to meet decommissioning obligations and leaving tax payers to bear the burden (Kaiser, 2015b; Kaiser & Liu, 2015). The government and society's objective is to have the operators bear the full cost of decommissioning liabilities. Ideally, an economic activity should bear both the private and social cost of production, else it creates externalities. Governments, through regulations, seek to reduce externalities by constraining the operators to internalize the social costs of production. For example, regulatory agencies with oversight responsibilities for decommissioning will seek to incentivize operators to timely complete decommissioning activities for uneconomic assets. This will help operators to include the cost of decommissioning liabilities and associated environmental liabilities from their operations, in the total production cost, which will be in accordance with the polluter pays principle.

Decommissioning is not an uncertain event as it must happen at some point in the future. The uncertain aspect is whether the operator will be able to meet the decommissioning obligation, when it occurs. According to the Project Management Institute (2013), a risk is “an uncertain event or condition that, if it occurs, has a positive or negative effect on a project’s objectives.” Hillson (2009) defined risk as “an uncertainty that matters” to set objectives. A default in meeting decommissioning obligations is an uncertain event that matters and could probably occur with some impact on revenue, environmental conditions, and societal well-being. Therefore, decommissioning liabilities default risk is the risk associated with default of an operator to meet decommissioning obligations at the end of economic life of a crude oil asset.

7.1.1. Assessment of Decommissioning Default Risk and Arising Issues

Every risk has an impact aspect, which in this case study is the estimated cost to meet decommissioning obligations either from a government standpoint or operator’s perspective, depending on who is the risk owner or executor of the decommissioning project. There is also the aspect of probability of occurrence, which is the chance that a default will actually occur.

As noted earlier, cost estimation for decommissioning is fraught with challenges. However, cost estimates can be inferred from historical actual project costs or reported decommissioning obligations in annual financial reports mandated by accounting standards. (Kaiser & Liu, 2014; Kaiser, 2015a; Kaiser & Liu, 2015). Therefore, cost estimates can be calculated even if it is to some stated low, but appropriate level of accuracy.

On the contrary, the chance of a default is not easy to estimate. There is not sufficient historical data to infer a credible likelihood that a specific operator will default to meet their decommissioning obligations. A default is dependent on many interrelated socioeconomic and political variables, such as divestment and its associated changes to ownership and operatorship structure. However, even with a small chance of occurrence, if it occurs, the impact of a default that could fall on tax payers and sometimes, non-beneficiary future generations, can be big. According to Johnson (2017), due to the high cost of decommissioning, the remaining tax revenue accruable to the UK from the North Sea may not be sufficient to pay for tax credits offered to operators after completion of decommissioning activities. The UK fiscal policy provides for operators to take tax credits for the actual cost paid for decommissioning activities in a field, to the limit of total taxes earlier paid from the particular field. Moreover, a default by any operator will make the full cost of the decommissioning project to be borne by the UK government.

In response, regulatory agencies have devised mechanisms to define the confidence that an operator will not default on decommissioning responsibilities at the end of economic life of its operations. Some common methods include the use of financial health of operators from publicly declared financial reports and balance sheets as proxies for risk metrics. The value of assets, market capitalization, and value of stated crude oil reserves are some of the popular proxies used. The value of assets in a balance sheet is dependent on the accounting assumptions used by the operator to prepare the financial report. Market capitalization varies with the stock market situation and also depends on other sociopolitical factors. The stated crude oil reserves, assuming credible reserves audit, is least susceptible to individual biases and relatively least dependent on inferred factors.

However, agencies do not still have a number on the chance of default based on these proxies. Instead, they compare these proxies with the cost of decommissioning liabilities to infer the level of confidence that an operator will not default. This is a measure of vulnerability to risk and not a quantification of risk. This takes the perspective from the measure of probability of default to the measure of vulnerability to a default event.

The vulnerability of the government to a decommissioning default event is an appropriate measure, considering that decommissioning will certainly occur and it is only the time of occurrence and whether the operator will be available to pay for it, that are uncertain. As a government does not have the privilege of escaping from decommissioning liabilities, its concern about vulnerability to the cost of decommissioning is tenable. Good sustainable development practice will also expect operators to be concerned about the vulnerability of their operations to the cost of decommissioning.

These challenges have created a need for a robust and reliable sense of quantification for exposure and vulnerability to decommissioning liabilities and indicator for its imminence of occurrence.

7.1.2. Sundry Efforts Toward Decommissioning Risk Metrics

As confirmed by Kaiser (2015b), interest in the decommissioning phase is low in the academic community. Most of the empirical approaches toward defining metrics for decommissioning risk are found among regulatory agencies. One of the main objectives of regulatory agencies for decommissioning in the UK and Alberta, Canada is the protection of tax payers from paying for decommissioning liabilities (Alberta Energy Regulator, 2016; Department for Energy and Climate Change, 2011). Accordingly, their metrics evaluate for the amount of financial security required from an operator to cover decommissioning liabilities from its petroleum production activities. In a collateral effect, the metric can also be used to incentivize operators to proactively complete their decommissioning projects properly. Regulatory agencies in the United States, UK, and Canada have made significant progress toward defining a measure for decommissioning risk in comparison to developing countries, such as Nigeria that have not made any visible progress.

7.1.2.1. Liability Management Rating (LMR): Alberta, Canada

The decommissioning liabilities, abandonment, and restoration management programs for petroleum field activities in Alberta, Canada are described as liability management programs (LMP). Under LMP, the quasi-risk or vulnerability metric derived and used for decommissioning liability risk management is the liability management rating (LMR). It is the "ratio of a licensee's eligible deemed assets" to its "deemed liabilities" (Alberta Energy Regulator, 2016). The objective is to maintain an LMR of not less than one for each licensee (Figure 37).

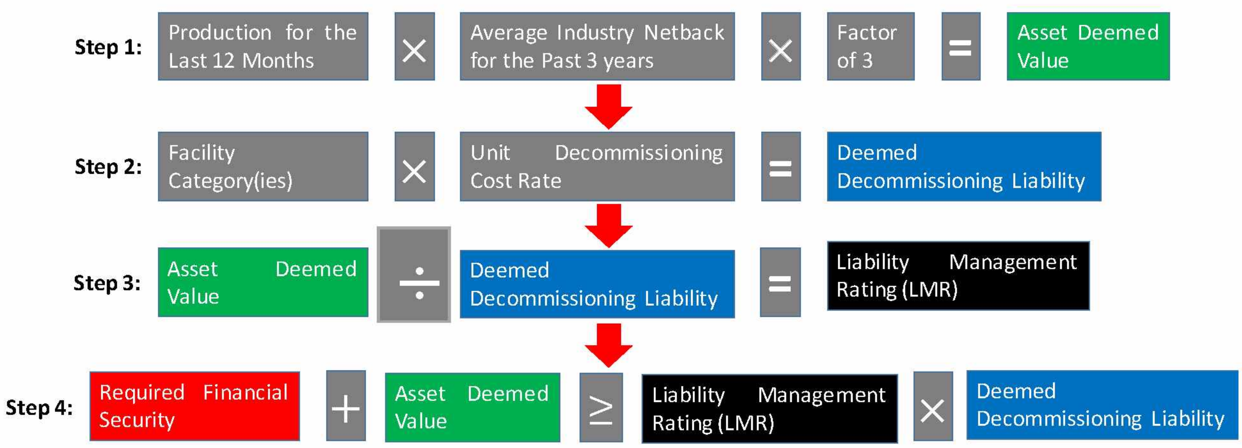


Figure 37: Illustration chart for Alberta Energy Regulator liability management rating

The deemed liabilities are generally expressed in terms of the estimated cost for suspension, abandonment, remediation, restoration, and reclamation of a facility or facilities for which an entity is the licensee of record. The programs have standardized and defined categories for the liabilities, which serve as scope parameters for decommissioning liabilities. Each scope parameter has defined unit cost rates. These are used to calculate the deemed liabilities in a way that provides consistency and transparency across operators. The deemed assets are calculated based on the "reported production rate from the preceding 12 calendar months in cubic meters oil equivalent"; the "3-year average industry netback," and a factor of 3 (Alberta Energy Regulator, 2016). A marginal deviation from this primary approach to LMR calculation occurs when an operator already provided some financial security instruments. They will be included as assets to calculate the LMR, which is then described as adjusted LMR. The LMR data for all licensees are revised and published monthly on the agencies website. For any gap in the deemed assets needed to bring an LMR to a value of one, some form of financial security is demanded from the operator.

The process is simple, consistent, transparent, and robust enough to adequately capture the cost of decommissioning liabilities and value of associated assets with the aim of determining and mitigating tax payers' vulnerability to decommissioning default risk.

7.1.2.2. Liability Management Rating (LMR): British Columbia, Canada

The BCOGC's decommissioning default risk metric is similar to that of AER and also described as LMR. While deemed liabilities are calculated through the same formula and methods as those of AER, deemed assets are calculated marginally differently. The deemed assets are based on reported volume produced in the last 12 calendar months multiplied by the industry netback and return period. The return period expressed in years replaces the nominal factor of 3 used in AER's formula. It is the key difference in BCOGC's approach. The return period is set at 3 years for raw petroleum production facilities, 1.5 years for oil waste management facilities, and is estimated through a formula for gas facilities. The reevaluation of LMR is undertaken monthly, after the collection of reported monthly production data from the Canadian government agency that collates oil and gas production data. A notice is thereafter issued on a monthly basis to operators with LMR less than one, to provide required financial security. The results are also accessible from the agency's website.

7.1.2.3. The United States Bureau of Ocean Energy Management (BOEM)

The BOEM estimates the cost of decommissioning liabilities associated with an asset and compares it with the net income and other financial health indices, such as current ratio from the balance sheet, credit rating from rating agencies, and liabilities in other fields, of each working interest partner involved in the asset. It does not use the value of reserves as undertaken by AER and BCOGC. Reevaluation is also undertaken if there are significant changes to operational arrangements in the fields (Bureau of Ocean Energy Management, 2016).

7.1.2.4. Comparison of Approaches

The BOEM approach is more elaborate in comparison to AER and BCOGC's LMR programs. It is more data and analysis intensive. Its estimates of net worth are biased toward company's financial indices and balance sheet information. The LMR and LLR approaches use the anticipated production volume and net revenue, which is more dependent on tangible assets than accounting judgment of net worth. Notwithstanding, the basic elements of these approaches are the determination of the remaining value or anticipated value from the assets, cost of meeting associated decommissioning liabilities, and the ratio between the two. While there are some differences in the details, the general approach is similar for most regulatory agencies. However, from our investigation, this form of approach to decommissioning risk evaluation has neither been undertaken nor does any form of decommissioning risk metric exist for onshore fields in Nigeria.

7.1.3. Formalizing the Metrics and Identifying their Limitations

Kaiser (2015b) attempted to formalize corporate decommissioning risk (CDR) as a metric for decommissioning risk. CDR is the ratio of the value of proved reserves to the total cost of decommissioning for a corporate entity. It is set at an aggregate level for several assets owned by a corporate entity in different regions. One challenge with the use of CDR as a decommissioning risk metric is the fact that by aggregating assets in different regions together, it clouds the sense of vulnerability at the asset level, particularly if a corporate entity does not operate exclusively in a region.

Kaiser (2015b) also developed another metric, asset decommissioning risk (ADR), which measures the ratio of the value of proved reserves to the cost of decommissioning for a particular asset, but ADR will require "specialized cost estimation and valuation models." Confidentiality requirements will prevent public access to information needed for independent calculation of ADR. Unlike aggregated regional data, asset specific data are rarely published in the public domain.

Based on the remaining realizable funds from the asset that can be used to pay for decommissioning, ADR and CDR may be proxies for probability to default. However, several other factors can influence an operator to default in meeting decommissioning liabilities, such as timing for decommissioning project along the cash flow profile instead of cumulative remaining revenue and corporate risk appetite. Fundamentally, these metrics provide only a snapshot, one moment and deterministic ratio of the cost impact of decommissioning to estimated remaining revenue. They do not provide insights into the future trend of this ratio. The metrics are also more of a representation of a corporation's vulnerability to the risk of default to meet decommissioning obligation than a measure of the government's vulnerability to decommissioning default risk.

Another less significant weakness with ADR and CDR is in the connotation of a quantitative measure for risk that includes a probability of default in meeting decommissioning obligations. While they are not effective measures of vulnerability to decommissioning default risk, they are also not a measure of risk as they are ratios that reflect only the impact and not the likelihood of a decommissioning default event. A risk is the product of the product of likelihood and impact of a decommissioning default event. As noted earlier, since there is not enough historical data on decommissioning default events, measuring the probability may be challenging. Therefore, these metrics do not represent a chance of a failure by a company to meet its decommissioning obligations, but a vulnerability to a decommissioning default event. For example, an operator can be a serial defaulter in several other environmental and business obligations, but still have a high CDR. To appropriately communicate these metrics, they need to be described as vulnerability ratios or metrics and not measures of decommissioning risk. Furthermore, as a region or country may have different fiscal elements yielding different streams of revenue, the metric should be expressed with respect to a specified stream of revenue. Adopting this approach could be more helpful to a government for fiscal planning and policy development purposes

Therefore, the emanating research question is, how do we effectively measure the vulnerability to decommissioning default risk with respect to available revenue streams and their trends, particularly for developing nations, such as Nigeria? The answer to this research question will help policy makers and public stakeholders to develop the appropriate revenue stream coverage strategy for decommissioning default risk.

7.2. Toward a Maturity Model for Sustainable Decommissioning Policy Framework for Crude Oil Fields

A corollary observation to the need of a vulnerability metric for decommissioning default risk is the need for a process performance measurement, monitoring, evaluation, improvement, and benchmarking framework. Monitoring entails regular gathering and analysis of performance indicators for a program or process that shows status of progress toward a set performance objective. Evaluation involves the objective, systematic, and comprehensive determination of the benefits of a program or process (Owen, 2006; Unger et al, 2015). Governments and the private sector performs monitoring and evaluation as a way to "ensure accountability for resource expenditure, inform strategic decisions, and to improve future performance through learning from past experiences" (Unger et al., 2015). Monitoring as a risk management element will help to ensure that problems are detected early and proactive mitigation actions are promptly taken (Kusek & Rist, 2004).

As noted earlier, there is a dearth of benchmarks for decommissioning of petroleum fields, particularly onshore fields in developing countries. There is not sufficient history of completed decommissioning projects in the petroleum industry in developing nations to use as a benchmark. Completed decommissioning projects in the developed nations are few, but also those completed are predominately offshore fields. However, there is a history of backlash from absence of or poor decommissioning frameworks for onshore fields in Texas, Pennsylvania in the United States and Canada. The orphan well programs with attendant financial, environmental, execution, and even political challenges are evidence of failure to comprehensively plan for sustainable decommissioning during the prime time of the petroleum fields.

7.2.1. Benchmarking and Maturity Models

Benchmarking is a mechanism used to evaluate a system or process for gaps and to support gap analysis toward continuous improvement that is aimed at the normative goals and aspirations. One of the successful tools for system or process gap analysis is the maturity model or graded rubric scales. "Maturity models establish a systematic basis of measurement for describing the 'as is' [current] state of a process." This characteristically described current status can be compared to the aspired status or goal or "contrasted with the maturity of other similar processes for benchmarking purposes" along those same characteristics or attributes (Institute of Internal Auditors, 2013). According to Tarallo (2016), it is used to "set process improvement objectives and priorities, and it can provide a method for appraising the state" or level of capability of an organizational, business, or political process. It is popularly used across sectors, industries, disciplines, system, and organizational processes. Caralli et al. (2012) defined it as "a set of characteristics, attributes, indicators, or patterns that represent progression and achievement in a particular domain or discipline." According to Fowler (2014), a maturity model "is a tool that helps people assess the current effectiveness of a person or group or [system or policy framework] and supports figuring out what capabilities they need to acquire next in order to improve their performance."

Characteristically, a maturity model will have "levels along an evolutionary scale that define measureable transition from one level to another [higher level]". The different levels in a maturity model depicts the level of effectiveness and associated capability requirements in a sequential format. It is expected that, to be at a certain level, the associated requirements must be met. Therefore, a maturity model is a guide that removes ambiguity and compels a definition of what is needed to attain a level of maturity, particularly if that higher level of maturity is desired. At a comprehensive level, a maturity model can help with the assessment of resources and the time it will take to attain a maturity level and support a judgment if attaining a higher maturity level is beneficial or not.

Maturity models are criticized for being too simple and sometimes inappropriate. However, as rebutted by Fowler, the simplification is the benefit of the model and "sometimes even a crude model can help you figure out what the next step is to take." Maturity models have also been criticized for being document-heavy and plan-culture-driven. For a public policy framework such as decommissioning framework for petroleum fields, it will be a benefit to be plan-culture-driven. From literature review and investigations, the fundamental elements for a sustainable decommissioning framework can be succinctly and simply described.

According to Tarallo (2016), maturity models were first developed by the Carnegie Mellon University in the 1980s, but the first tool capability maturity model integration (CMMI) was released to address the problem of capability development in the software engineering industry. However, Caralli et al. (2012) noted that Carnegie Mellon University's work on maturity models were preceded by Richard L. Nolan's work on staged maturity model at Harvard University in 1973. Maturity models have since evolved and found use in several industries, sectors, business processes, and disciplines. They are popular in project management, software engineering, cyber and physical security, logistic, manufacturing, operations, healthcare, power, infrastructure, and even decommissioning/remediation of solid mineral mines (Caralli et al., 2012; Tarallo, 2016). Ernst & Young (EY) have a physical security maturity model and a cybersecurity model, both developed from the CMMI tool (Tarallo, 2016). In project management, there are maturity models, such as the project management maturely model developed by Project Management Solutions, Inc. The model is still based on the CMMI (Crawford, 2015). In addition, de Souza & Gomes (2015) also observed other types of maturity models in project management, such as organizational project management maturity model by PMI, Kerzner project management maturity model developed by Harold Kerzner, and project management maturity model (MMGP) developed by *Instituto de Desenvolvimento. Gerencial* (Management Development Institute, INDG). There are several more types of maturity models. However, extensive investigation from this study shows none has been developed for decommissioning in the petroleum industry.

Maturity models helps to "create a consistent way of thinking and communicating about" (Caralli, 2012) an issue, such as decommissioning, by leveraging the model's taxonomy and levels (Ormazabal, 2013). Apart from helping with benchmarking and gap analysis which will drive national or organizational improvement toward sustainable decommissioning, it will also help to ginger a wider petroleum industry or sector improvement toward sustainable decommissioning. Using the decommissioning maturity model, nations and organizations will have a common basis for comparison amongst themselves, across industries in the energy and non-renewable sector, and even across nations. Through its need for collaborative input data, the use of maturity models brings transparency and accountability to a process. Nations and organizations can self-verify or be evaluated by a third party on how much improvement they are making toward sustainable decommissioning. According to Institute of Internal Auditors (2013), it provides "a disciplined method that comparatively is easy to understand and implement" to improve on the effectiveness of a process. This simple, but pragmatic means of comparison was lacking in the World Bank's study of 2010. There is some measure of benchmarking for the cost estimate of decommissioning frameworks in the oil gas sector in the UK by the industry trade organization Oil and Gas UK and for decommissioning in the nuclear industry (Thomas, 2017).

However, there is no comprehensive benchmarking tool for decommissioning in the petroleum industry, such as the jurisdictional maturity model for the solid mineral mines industry developed by Unger et al. (2015). Focusing on the problem of abandoned mines in Australia, Unger et al. (2015) developed a jurisdictional maturity model "for the evaluation of abandoned mines remediation programs" across different jurisdictions in Australia and British Columbia in Canada.

7.2.2. Types and Structures of Maturity Models

There are different types of models based on different sectors, industries, or organizational process objectives. However, Caralli et al. (2012) grouped them into three main types, progression models, capability models, and hybrid models. Adopting the definition by Caralli et al. (2012). Progression maturity models represent a simple progression or scaling of an attribute, characteristic, pattern, or practice. the movement up the maturity levels indicates some progression of maturity. An example is SGMM or the progress from pencil and paper ➔ abacus➔ calculator➔ computer. Capability maturity model is focused on progression with a particular aspect of an organizational capability represented by a set of attributes, characteristics, patterns, or practices, which are measured. The incremental levels of progression can be represented as ad hoc ➔ managed ➔ defined ➔ quantitatively managed ➔ optimized. An example is the CMMI. A hybrid maturity model is a blend between the progression and capability maturity models. This study considers that the distinction between the types of models is not significant and that models are crafted to suit the evaluation objectives. Maturity models either developed or selected from existing models have to be fit for purpose, relevant, and adequate (Institute of Internal Auditors, 2013).

Irrespective of the type, the essential characteristics are that the model must have levels, domains or elements, attributes, appraisal, scoring methods, and improvement roadmaps (Caralli et al., 2012). Davidson (2005) highlighted that a maturity model as an evaluation rubric will have a set of evaluative criteria that described the aspect of performance that are of interest to the evaluation and another element for merit determination, which will reflect the graded levels used to rank performance under each of the evaluative criteria. The evaluative criteria relate to the model domains and the merit determination relates to the levels of maturity.

The levels of maturity are series of progressive steps depicting higher attainment of capability or development of attributes measured by the model. “A low level of maturity implies a lower probability of success in consistently meeting an objective, while a higher level of maturity implies a higher probability of success" (Institute of Internal Auditors, 2013) with respect to those process elements that could lead to better effectiveness of the process, which in this case is the decommissioning framework. Most maturity models have five or six levels, even though some do have seven or three levels. EY maturity models have five levels, level 1 through level 5 with level 1 defined as initial, level 2 as repeatable, level 3 as defined, level 4 as managed, and level 5 as optimized. Level 1, which is the initial level, is characterized with unpredictable, poorly controlled, and reactive process and level 5, which is optimized, is characterized with well-established, managed, and defined process. The project management maturity model also has five similar levels, level 1 is the initial process, level 2 is the structured process and standards, level 3 is the organizational standards and institutionalized process, level 4 is the managed process, and level 5 is the optimized process (Crawford, 2015). OPM3 project maturity model has four levels of maturity. Level 1 is standardized, level 2 is measurement, level 3 is control, and level 4 is continuous improvement. However, from a survey, de Souza & Gomes (2015), observed that the CMMI model is most popular with approximately 82% adoption. Unger et al. (2015) jurisdictional maturity model for mines remediation programs also has five levels – level 1 is vulnerable, level 2 is reactive, level 3 is complaint, level 4 is proactive, and level 5 is resilient. This study will adopt the five hierarchically maturity levels, similar to five levels in Unger et al.'s jurisdictional maturity model for abandoned mines programs (Figure 38). The five levels also provide more latitude for discrimination than four levels.

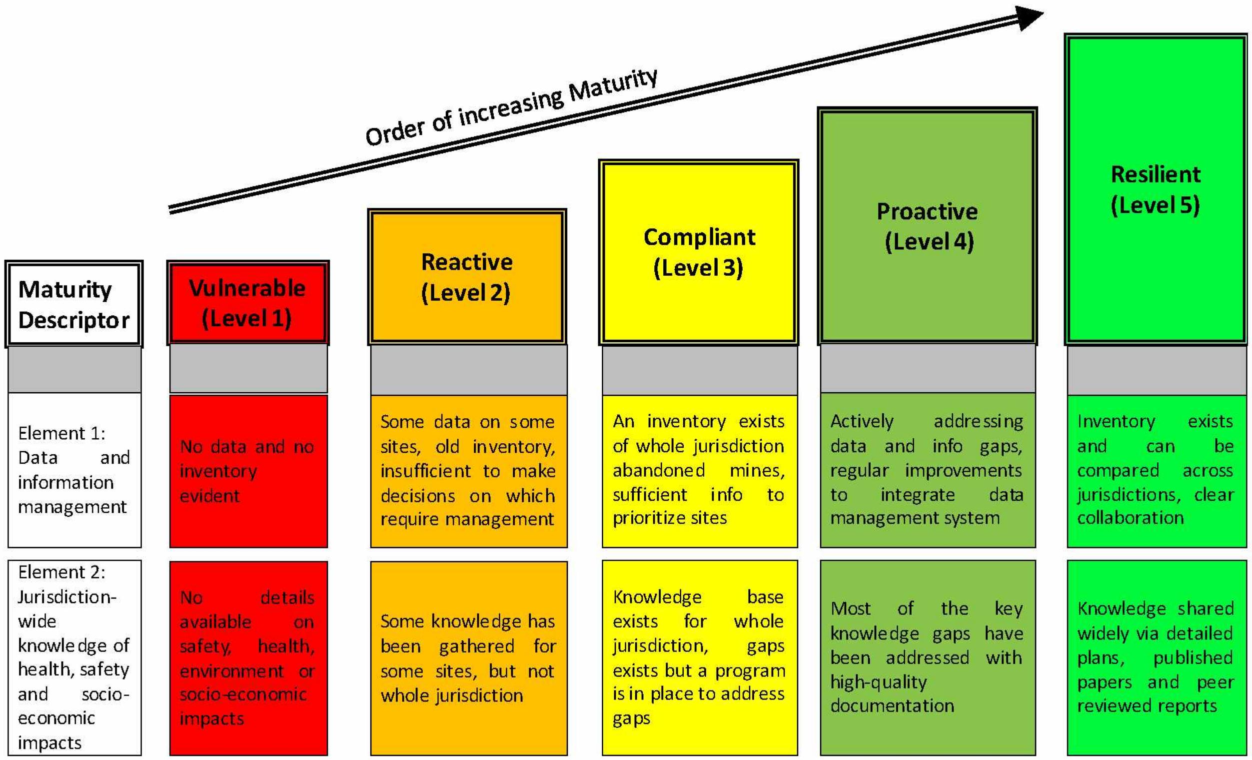


Figure 38: Modified presentation of Unger et al.(2015) jurisdictional maturity model for abandoned mines in Australia

The model domains are groupings of attributes, criteria, or elements required of the system or process being evaluated. While the domains can be many, restricting them to a few domains will help keep a model from becoming complex and losing the benefit of simplification of a complex system that a model brings. The PMMM3 adopted 10 knowledge areas of project management – project integration, project time, project scope, project communication, project cost, project quality, project stakeholders, project risk, project human resources, and project procurement as outlined by the project management institute (PMI) as the model domains or evaluative criteria. The jurisdictional maturity model for abandoned mines programs (Figure 38) has 14 evaluative socioeconomic and environmental criteria or domains. The 14 evaluative criteria are (i) data/information management, (ii) jurisdictional-wide knowledge base of impacts and opportunities (health, safety, environmental, and socio-economic, (iii) site specific data for high risk/priority sites, (iv) leadership, legislation, policy, and guidance to address abandoned mines, (v) leadership, legislation, policy, and guidance to prevent new abandoned mines, (vi) risk assessment and prioritization of programs (vii) abandoned mine program leadership and capacity (viii) funding–sources, mechanism, and resources, (ix) beneficial post-mining land use, (x) heritage conservation–indigenous and industrial, (xi) secondary or complementary mining opportunities (industrial ecology), (xii) resourcing in partnership, (xiii) stakeholder management, and (xiv) communication and networks (Unger et al., 2015).

While having several domains or evaluative criteria may appear to be exhaustive, the simplification benefit of the model may be eroded. The normative aspiration will be to review the criteria down to only the essential requirements and have them succinctly described. This will make it easy for the maturity model to be adopted and continuously utilized for sustainable decommissioning policy development, monitoring, evaluation, and implementation in developing countries with weak institutional capacities and even corporate bodies that cherish agility The attributes are "typically based on observed practices, standard, or other expert knowledge" used to define the domain and should be amenable to measurement and evaluation. The appraisal and scoring methods define consistent methods and standards of measurement across the levels (Caralli et al., 2012). Basically, these will be a set of objective description of what a level of maturity entails for each evaluative criterion. To define these attributes, Unger et al. (2015) used a comparison between leading and best practices for each evaluative criterion to help guide the definition of these attributes. For sustainable decommissioning, a few leading practices exist or in the alternative, there are normative aspirations for sustainable natural resource development that can be used as a guide to define the attributes.

7.2.3. Proposition – Sustainable Decommissioning Policy Framework Maturity Model for Petroleum Fields

An improvement roadmap is an inherent outcome of the maturity model as it shows the gaps and required attributes, capability, or requirement needed to attain a higher level.
Ministerial Council on Mineral and Petroleum Resources and Minerals Council of Auatralia (2010) and Unger et al. (2015), in their studies on abandoned mines, agreed that maturity models will be useful tools to support development and implementation of abandoned mines policy framework in a country. Considering the similarity between mines and crude oil fields as common pool natural non-renewable resources, this should similarly apply to decommissioning of petroleum fields. This approach can also show if the policy and program are performing effectively, and hence incentivize stakeholder's intervention to ensure sustainable decommissioning of these fields. Therefore, the research question is, can there be a similar graded rubrics or maturity model for sustainable decommissioning of crude oil fields to demonstrate the status of exposure and level of preparedness for the decommissioning phase and its liabilities, improvement in performance of the decommissioning policy frameworks and programs over time, and to support continuous improvement plans? This study developed and presented a graded scale maturity model for sustainable decommissioning of petroleum fields described as "Fairbanks graded scale maturity model" in chapter 8, Research Methods and Methodology.

8. Research Methods and Methodology

This chapter succinctly recaps the identified knowledge gaps from the literature review on decommissioning with particular reference to onshore crude oil fields in Nigeria. It presents the gaps as an undergird to the research objectives and significance of this study. This is followed by an elaborated description of the research problem and questions. This chapter also describes the basis for the adopted research methodology, data gathering, and data analysis techniques.

8.1. Summary of Knowledge Gap from Literature

From the literature review, there is paucity of academic studies on decommissioning of oil fields (Figure 39). This is also reflected in comparison with the mining and nuclear industries, which have some extensive research works on mines and nuclear site closures. Globally, the paucity is relatively more with onshore fields in comparison to offshore fields which have some case studies conducted on the GOM, UKCS, and Malaysian and Brazilian offshore fields. Even with offshore decommissioning, most of the discussions are on the subject of law and financial assurance.

While Kaiser (2006a; 2006b; 2015a; 2015b;) and McEown (2017) acknowledged the challenges with proprietary nature of data on decommissioning and decommissioning cost estimation methods, none of the existing studies attempted to consider how the challenges could be overcome with only publicly available data. Kaiser used settled liabilities to determine the cost of decommissioning for offshore platforms in GOM, but still made use of some proprietary data on completed decommissioning scope of work which his study was privileged to access.

There is a knowledge gap on how only publicly available data can be used to determine the cost of decommissioning liabilities and vulnerability to decommissioning default risk, particularly for developing countries such as Nigeria. A good measure of vulnerability to decommissioning default risk will incentivize stakeholders to drive sustainable decommissioning policy development. The available methods to define vulnerability to decommissioning default risk in the industry are too complex for the public, fraught with challenging input information requirements, and are so inexpressibly described that, stakeholders' effective participation in the policy development process for sustainable decommissioning of petroleum fields is inhibited, particularly in developing countries such as Nigeria.

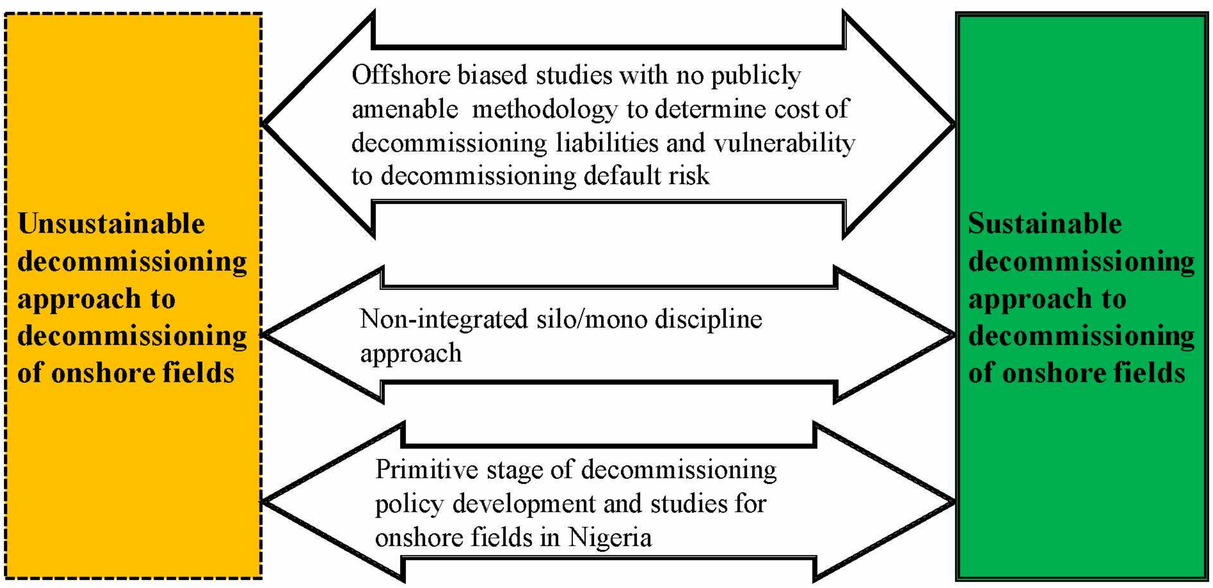


Figure 39: Knowledge gap on sustainable decommissioning of onshore fields

Sustainable decommissioning is an interdisciplinary challenge encompassing not only legal issues, but technical, economic, environmental, and social aspects of petroleum engineering. Existing studies on decommissioning which are more biased toward offshore fields are predominately from a single discipline or silo perspective. A sustainable decommissioning strategy will require effective engagement and commitment of public stakeholders, particularly in the oil producing areas. Engagement and commitment of pubic stakeholders to a sustainable decommissioning public policy will be enhanced if there is public knowledge of a country or region's vulnerability to decommissioning default risk. An integrated method to determine vulnerability to decommissioning default risk will be interlinked with the determination of the cost of decommissioning liabilities and size of associated remaining revenue from the crude oil reserve.

Consequently, overcoming challenges with proprietary data and disparate stakeholder awareness on decommissioning will not only require a focus from economics and cost estimating disciplines, but technical, environmental, and social aspects of petroleum engineering. With the current and prevalent approach of considering decommissioning from a single subject perspective, existing studies on decommissioning of petroleum fields, particularly onshore fields, have been lacking an interdisciplinary approach, which is essential to effectively address the challenges of decommissioning. This study will take an interdisciplinary approach to address the challenges of decommissioning in the petroleum industry.

This situation is even worse for academic works on decommissioning and abandonment of onshore oil fields in Nigeria. Ayoade (2002), Azaino (2012), and West (2014) similar to most authors, considered the legal issues associated with decommissioning, but for only offshore fields in Nigeria. From investigations in this study, there is paucity of literature on decommissioning of petroleum fields in Nigeria and most of the existing literature and studies are focused on offshore fields. Apart from Lawal's (2008) study on stakeholders' perception of accountability expectation gap for decommissioning of oil fields in Nigeria, there is no other comprehensive study on decommissioning policy or data on empirical societal perception, talk less of a study on vulnerability to decommissioning default risk for oil fields in the Niger Delta onshore region of Nigeria. Ibebuike (2013) and Dawodu (2016) undertook some studies on decommissioning related to the exit of IOCs from the Niger Delta onshore region of Nigeria, but considered it majorly from the perspective of asset sales and associated legal issues. Lawal (2008) identified the existence of accountability expectation and information disclosure gaps on decommissioning amongst stakeholders in the Nigeria petroleum industry. He discovered that there was limited or no consideration for decommissioning in the thought process that went into the development of the existing JV agreements for onshore oil fields in Nigeria.

It can be concluded that a knowledge gap exists in academic works on policy development, particularly the necessary elements of cost and vulnerability to decommissioning default risk for the Nigerian crude oil fields in general and Nigerian onshore crude oil fields in particular. Moreover, in the academic or public space, there is no primitive description of the cost of decommissioning liabilities for the onshore crude oil fields and the vulnerability of the Nigerian public to decommissioning default risk from these fields. Contributing toward the closure of this knowledge gap is one of the objectives of this study.

8.2. Objectives of the Study

The objectives of this study are to

- Develop a simple and public-amenable methodology to determine the cost of decommissioning liabilities for a region or entity, using only publicly available and reliable input information.
- Develop a simple and public-amenable methodology to evaluate and determine vulnerability to and imminence of decommissioning default risk.
- Seminally demonstrate the looming size of decommissioning liabilities, and the vulnerability to and imminence of decommissioning default risk for the onshore fields in Nigeria.
- Develop a simple and public-amenable methodology to benchmark the level of preparedness and maturity of frameworks for sustainable decommissioning of petroleum fields.

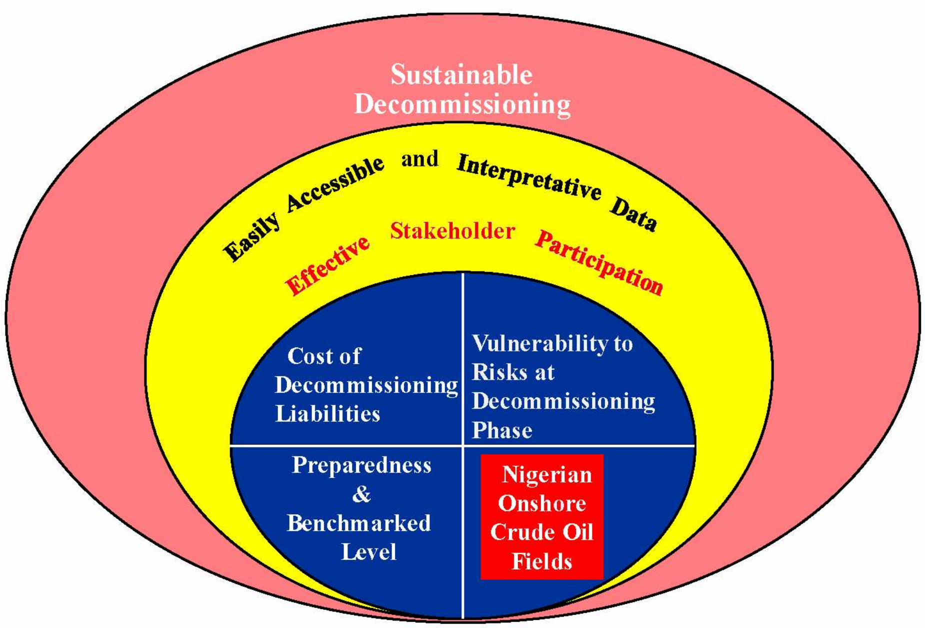


Figure 40: Objectives of this study

Sustainable decommissioning requires sufficient and appropriate information for a comprehensive policy development. It also requires effective and vigorous stakeholders' participation, which is dependent on stakeholders having easy access to appropriate and easily interpretative information on cost and vulnerability to decommissioning liabilities. Therefore, the overarching objective of this study is to help ensure that society's aspiration for sustainable decommissioning of petroleum fields is not defeated by the proprietary challenges associated with public and government's access to information on decommissioning, and the complex evaluation methodologies for cost of decommissioning liabilities and vulnerability to decommissioning default risk in the petroleum industry (Figure 40). By doing so, the study can also contribute to knowledge in decommissioning of petroleum fields in general and Nigerian onshore crude oil fields in particular.

8.3. Significance of the Study

One of the significance of this study lies in the presented new methodologies that require only publicly accessible input information to determine the cost of decommissioning liabilities, and vulnerability to and imminence of decommissioning default risk for countries or entities. It addresses the deficiencies of the current snapshot one-dimension indicator for vulnerability to decommissioning default risk for corporate entities, petroleum resource regions, and governments.

Gaining access to information on decommissioning has always been an almost insurmountable challenge to the public and sometimes for government regulatory agencies trying to determine the cost of decommissioning liabilities. By leveraging the outcome of this study, governments and public stakeholders can easily acquire this information and be incentivized to appropriately participate in the policy development process toward sustainable decommissioning in the petroleum industry.

This study also extends the existing decommissioning coverage ratios currently described at corporate or individual assets level to a regional or country level, and improved on the development of the ratios to seminally demonstrate their representation of vulnerability to decommissioning default risk and the imminence of its occurrence. In the existing literatures investigated, decommissioning coverage ratios have not been appropriately described as vulnerability ratios and there has not been any public-amenable indicator to demonstrate the imminence of decommissioning default risk in the petroleum industry in general and Nigerian onshore fields in particular.

Furthermore, from literature investigation, decommissioning policy development is still ambiguous in Nigeria. The government provided limited or no consideration to decommissioning at inception of the field development plans and did not thoroughly consider decommissioning in the JV agreements with the operating companies (Lawal, 2008). Decommissioning is looming, but the stakeholders are oblivious of the risk. The public do not have an idea of the cost and implications of the decommissioning and environmental liabilities that could fall on the government to pay, if the operating companies fail to properly decommissioning the fields (Stakeholder Democracy Network, 2015). Stakeholder engagement for decommissioning of oil fields and closure of mines is generally low in developing countries, such as Nigeria (World Bank, 2010) and regulatory policy frameworks are also less mature (Azaino, 2012; Kelani, 2009). After approximately a century of oil exploration in the Nigerian onshore region, there is no tangible and measurable effort toward sustainable decommissioning of the onshore crude oil fields. The ghost of this same malady looms from the unmanaged abandonment phase of the coal industry in Nigeria (Ezemokwe & Maduibuike, 2015; International Centre for Investigative Reporting, 2017; Odesola et al., 2013). Reserve addition and related activities for onshore fields in Nigeria have been so low that they may be classified as mature fields (Campbell, 2013). In addition, MOCs have started to divest from these fields, similar to divestment activities in other mature crude oil producing regions of the world, such as UKCS, GOM, Gabon, Alaska (British Petroleum, 2014; Kaiser & Liu, 2014; Kaiser & Pulsipher, 2008; Kemp & Stephen, 1998; Shell Global, 2017). According to Obasi (2013), approximately 50% of the stakes of the major MOCs in Nigerian onshore fields have been divested since 2009. These fields are already in the production decline phase and are relatively no longer as attractive to MOCs to continue keeping them in their portfolios. There is an increasing trend of IOCs exiting the onshore regionr, but no clear strategy exists to manage their exit and address the decommissioning liabilities being left behind. It could be conscionable that the emerging exit strategy is an elopement from decommissioning obligations. After all, according to Boyd & Ingberman (2003), dissolution can be a rational method to avoid future obligations, even though it could be socially irresponsible. Therefore it is appropriate at this time to initiate a discussion about decommissioning of these fields, and the associated environmental and socioeconomic risk.

A sustainable decommissioning approach will attempt to assess the risk associated with decommissioning of Nigeria's onshore fields, identify the credible scenarios and time line, and seek for an optimal socioeconomic mitigation strategy. Less developed countries such as Nigeria that may be reluctant to expend financial resources on planning for decommissioning, will desire to have easy ways to know how much and how imminent is their exposure to decommissioning liabilities. This will help them to better acknowledge the urgency to develop appropriate risk response strategies. Hence, another significance of this study is the seminal determination of a baseline cost of decommissioning liabilities for onshore fields in Nigeria. Hitherto, in the public and academic space, there has not been any rough order magnitude cost estimate for decommissioning liabilities for the petroleum industry in Nigeria. Due to lack of relevant data on production decline, low awareness about problems of decommissioning and its imminence, there are limited efforts toward the development of decommissioning, site restoration, and environmental clean-up plans for the onshore fields (Stakeholder Democracy Network, 2015). To the best of my knowledge, this study is the first attempt to evaluate the vulnerability to decommissioning default risk for the petroleum industry in Nigeria and to determine the imminence of decommissioning for onshore fields in Nigeria.

This is an exploratory study on decommissioning of onshore crude oil fields in Nigeria. It will provide a foundational baseline for sustainable decommissioning policy development for these fields in Nigeria. By leveraging the study results, relevant stakeholders will be provided with adequate and appropriate information needed for comprehensive and effective policy development and management of the decline phase of Nigerian onshore crude oil fields.

This study will also serve as a frontier knowledge platform for further research on cost estimation and risk evaluation for sustainable decommissioning policy development and management in the petroleum industry. It also introduces decommissioning of Nigerian onshore fields in particular, into the academic space.

8.4. Research Problem Description

From literature review and investigations in this study, there is a dearth of publicly accessible information on cost of decommissioning liabilities in the petroleum industry. There is also, no simple but comprehensive measure for vulnerability to decommissioning default risk in the petroleum industry. This is inhibiting effective stakeholders' participation in policy development for sustainable decommissioning in the petroleum industry. Particularly, considering the case study Nigerian onshore region, it appears there is no significant consideration and plan for the potential end of economic extraction of crude oil from these fields. Even with the increase in numbers of MOCs exiting onshore fields in the last few years, the focus is still on preferential access to economic benefits from crude oil extraction without a consideration for the penalties of the decommissioning phase.

There may be other contributing factors, such as the need for portfolio rationalization, optimization, and economics of scale associated with this emerging scenario. However, could a natural depletion driven production decline and associated uneconomic outcome also be a contributing factor? The coal industry in Nigeria shows a poor example of an unmanaged transition from economic to uneconomic phase of natural resource development. In Canada, UK, GOM, and several other fields in the United States, individual fields and entire regions have witnessed transition from economic to uneconomic phase of natural resource developments in the solid mineral and petroleum industries. While decommissioning is a pertinent feature in development plans, activities, and policies in these developed nations, it is scarcely discussed in Nigeria. The potential problem of decommissioning of onshore fields in Nigeria is being ignored either deliberately or out of ignorance or both. Lawal (2008) observed an accountability expectation gap between stakeholders on decommissioning of offshore oil and gas fields in Nigeria. His study pointed the lack of clarity and alignment on regulation as some of the main reasons for the gap. The lack of clarity is linked to propriety nature and lack of publicly available information on elements of a decommissioning policy, such as size and cost of decommissioning liabilities, likely time for decommissioning to commence, and remaining production volumes among other reasons (Kaiser, 2015a; Rogers & Atkins, 2015).

Decommissioning of offshore petroleum facilities in Europe, North America, and Asia is very much under international scrutiny due to the fact that most of these operations are in international waters and the countries have signed international treaties. Apart from the relatively more mature levels of government policy development in these countries, the international policy and political influence on decommissioning is more for offshore fields than onshore fields in Nigeria. Onshore fields in Nigeria are not under the ambit of any directly enforceable international treaty. Therefore, in comparison to onshore fields, decommissioning of offshore fields have been more discussed. There are also, some literature on comparative analysis of technical scope, legal regimes, and framework for offshore fields (Ayoade, 2002; Kaiser, 2015a; West, 2014). The few empirical reference studies on decommissioning of onshore crude oil fields either in the United States or Canada are in isolation and have not been used for international comparative studies which could yield benefits of lessons learned to other developing nations with onshore fields. Likewise, there is a paucity of transfer of lessons learned from decommissioning of offshore fields to onshore fields.

The increase in field development projects and crude oil production from offshore fields in Nigeria is masking production decline from the onshore fields, and possibly creating a deception that time for decommissioning of onshore fields is still far away. Another deception could be the assumption that international approaches to decommissioning in offshore fields will suffice and could be easily translated to decommissioning in Nigeria. While this may even be conscionable for offshore fields, it may not be for onshore fields.

In summary, the priority attached to decommissioning of onshore fields and decline phase of Nigerian onshore crude oil fields is vague. Stakeholders are not actively aware of the potential liabilities of decommissioning Nigerian onshore fields owing to the proprietary nature of information related to decommissioning. Consequently, they are not invested in policy development toward sustainable decommissioning of the fields. Sustainable decommissioning of onshore fields in Nigeria is too data intensive for public stakeholders and too convoluted to be measured and managed; hence, the poor level of policy development. There is no assurance that the fiscal policy may be robust enough to effectively mitigate the potential problems with decommissioning of onshore fields in Nigeria. As a result, the onshore crude oil fields in Nigeria, similar to other regions in the world with immature decommissioning policy frameworks, could be left improperly decommissioned in the future with no available responsible operator to pay for the decommissioning when it eventually occurs. Future generations may be left to bear the burden of decommissioning of the onshore crude oil fields alone and without adequate bequeathed capital to pay for the decommissioning liabilities.

These thematic issues and context, and their resultant dialectic interactions raise the research questions on sustainable decommissioning of onshore crude oil fields in Nigeria.

8.5. Research Questions

Using Nigerian onshore crude oil fields as a case study, following are the research questions:

i. Is there a method to overcome the information asymmetry in the petroleum industry to know the size and cost of decommissioning liabilities arising from crude oil fields? The corollary objective seeks a methodology to estimate the cost of decommissioning liabilities for onshore fields in Nigeria from publicly available data.

ii. What is the vulnerability or exposure of the government/public to the risks resulting from decommissioning of onshore fields and the imminence of its occurrence? The corollary objective seeks to ascertain if there will be sufficient resources to pay for the proper decommissioning of onshore crude oil fields in Nigeria when it occurs, and a determination of its imminence of occurrence.

iii. Is there a method to benchmark the level of preparedness for the decommissioning phase of crude oil field amongst nations or entities so as to systematically and progressively drive improvement toward sustainable decommissioning policy development? The corollary objective seeks to develop a maturity model for sustainable decommissioning policy framework for crude oil fields.

8.6. Research Methods

The research methods adopted for a research are informed by the research objectives, significance, and subjects of the study. This study cuts across natural and social sciences – petroleum engineering, environmental engineering, engineering and project management, natural resource economics, and policy development and administration. Therefore, it is easily suited for a mixed research method approach, using qualitative, quantitative and explorative research methods. Corbin & Strauss (2008) and Kumar (2013) described a qualitative and explorative approach as suitable for a research that has to identify and understand empirical knowledge about a phenomenon.

Instead of nominalist ontology, this study will be conducted under a realist ontology. A nominalist perspective will suggest that the issue of sustainable decommissioning is being viewed from a prism of ideal situation. Sustainable decommissioning can be assumed to exist only in the individual's consciousness under this perspective. Even though there could be an extreme case for this position, on the contrary, there are existing and leading practices and operations toward sustainable decommissioning in the offshore sector in developed nations and other natural resource industries. In addition, there are similar identifiable positive trends in other countries, such as the UK, Canada, and the United States. There are realistic empirical trends observable in the offshore petroleum sector too. The phenomenon of sustainable decommissioning of onshore fields in Nigeria is a social reality issue. Therefore, a realist ontology is a suitable approach to investigate the phenomenon of sustainable decommissioning of Nigerian onshore fields. This philosophical position supports the adoption of a case study approach with the adoption of modeling and scenario planning as research methods for this study.

Scenario planning and analysis involves the description of different plausible pictures or scenarios of future events related to the topic, the interlinks between the events, and analysis of gathered data in the perspective of future scenarios (Lindgren & Bandhold, 2003; Ramirez et al., 2015; Schoemaker, 1995; Stone & Redmer, 2006). Scenario planning is used by several MOCs for business planning (Shell International Limited, 2005) and as a data analysis method in policy studies (Kirby & O'Mahony, 2018). The scenarios identified for the EOFL of Nigerian onshore crude oil fields will also be described in chapter 9, Results and Results Analysis.

In natural sciences, such as petroleum engineering and social sciences, modeling is a research method used to evaluate whether some natural phenomenon emanating from physical laws of science underlay the observed data. Al-Thani (2002) described a model as a "representation of a chosen reality," and adopted modeling as a research method for a doctoral dissertation on comprehensive evaluation of oil and gas field projects in Qatar. Models have been commonly used for research in petroleum engineering, particularly in the area of reservoir engineering. Several types of petroleum reserves and production rate forecasting models have been developed (Adamu et al., 2013; Akinwale & Akinbami, 2016; Akuru & Okoro, 2011; Echendu, 2011; Jakobsson, 2012). Kingsley-Akpara & Iledare (2014) applied Hubbert modeling to total crude oil production data in Nigeria. Oladeinde et al. (2015) also applied a mathematical regression model to predict a typical output from a Nigerian oil field. Generally, models have been used to postulate expected future behaviors for project outcomes and future crude oil production. While predictions made using results from models are commonly taken as important, there are still compelling observations that “no model has been prescribed that consistently delivers reliable prediction of future production rates” (Jakobsson, 2012). Some authors would argue that models are “useful only in so far as the particular representation embodied within the model meets a particular defined need” and issues that are more particular to the results from the model can be addressed through a sensitivity analysis (Al-Thani, 2002). Friedman (1953) had earlier laid the ground that assumptions should not be expected to be descriptively realistic in a model, but “sufficiently good approximations for the purpose in hand.” Jakobsson (2012), citing Troitzch, noted that models are more likely to predict the general behavior than exact and specific outcomes, not because there is lack of “knowledge of causal mechanism, but rather the inability to observe all the relevant variables.” As a result, more granular, detailed, and precise models will not necessarily lead to an exact quantitative prediction. Therefore, results from models are qualified to depict the associated subjectivity of the modeler and are sometimes better reflected in probabilistic terms. As pointed out by Jakobsson (2012), “the inability to make exact quantitative predictions does not make modeling meaningless.” Models can be used for different purposes, amongst which is predicting qualitative behavioral trend and providing normative recommendations for policy guidance, such as decommissioning of onshore fields in Nigeria (Al-Thani, 2002; Epstein, 2008; Jakobsson, 2012; Kemp & Stephen, 1998). Compagni (2015) noted that a model should be as representative of reality as possible, but not be too complex in a bid to capture the entire reality as it would then “give the modeler no more information than studying [the complicated] reality directly.” Jakobsson (2012) declared that a model is “pointless if it is not simpler and more manageable than the reality it represents,” which echoes Friedman’s (1953) view that realism should not be the overarching goal of modeling. Seeking to meet the research objectives, this study developed four methodologies, each with a resulting model to investigate the key issues related to decommissioning and to answer the research questions.

8.6.1. Production Decline Curve Analysis (DCA) Methodology and Nigerian_Onshore_Production_Decline_Model

Okullo (2013), in modeling long term scenarios for oil supply and price, distinguished between top-down and bottom-down model approaches. The top-down model approach is more focused on behaviors within the model at a relatively more aggregate level in comparison to the bottom-up model approach which is more granular. This study will adopt a top-down modeling research method by using the production DCA model to test for a natural depletion driven declining phenomenon in the historical production data from onshore fields in Nigeria. Production decline curves have been used to predict future production from several crude oil fields (Jakobsson, 2012; Lynch, 2002; Poston & Poe, 2008) and for countries, regions, and plays (Hook et al., 2009; Lund, 2014; Munisteri & Umekwe, 2017). The DCA model will be described as "**Nigerian_Onshore_Production_Decline_Model.**" Both deterministic and probabilistic future behaviors of production profiles for onshore fields in Nigeria will be determined based on results from the "**Nigerian_Onshore_Production_Decline_Model**". Beninger & Caldwell (1991), and Kamari et al. (2017) severally supported this approach.

8.6.2. Decommissioning Liabilities Cost Estimating Methodology and Nigeria_ARO_Cost_Model

The decommissioning liabilities costing methodology and resulting model developed in this study will use input information from publicly available data on decommissioning to predict the aggregate cost of decommissioning liabilities for a region, such as onshore fields in Nigeria. It recreates decommissioning liabilities cost from publicly available decommissioning data following the methodology in Figures 41 and 42. It is the reverse of the process used by corporations for the determination of ARO cost in financial reports. Even though the entire detail information behind the reported ARO data are often not explicitly declared by oil companies, the methodology introduced in this study and the resultant cost estimation model "Nigeria_ARO_Cost_Model" that will be demonstrated with onshore region in Nigeria, provides for credible assumptions from publicly accessible sources. Every asset or region in the world can be suited to use this model, if the companies operating in the area are required to publicly declare financial reports of their operations in the commencement year of their involvement with the oil field operations and continue to publicly declare their financial reports annually or periodically thereafter.

The model is better described through a hypothetical scenario of an oil company that is in a JV agreement with the government. The oil company is the operator of the asset. It charges the JV for its cost of operations, which includes the cost of decommissioning, if the decommissioning is completed. Therefore, the cost of decommissioning will also be equitably shared amongst the JV partners, including the government. However, if the JV partners exit the fields without paying their portion of the decommissioning cost, the government will be socially obliged to bear the burden of payment for the total cost of decommissioning liabilities. The parameters for the models are outlined and described in section 8.6.1.2.

(I) Identify required data from financial reports

a) Year of Report or Data Y_{report}
b) ARO cost C_{WI}
c) Number of Gathering Stations Captured in Scope FS
d) Government Joint Venture Interest JV_{govt}
e) Working Interest $WI_{operating}$
f) Economic End of Field Life Y_{EOFL}
g) Discount Rate r
h) Inflation Rate i
i) Escalation Factor UCCI U_{index} extracted from IHS/CERA UCCI report

⇩

(II) Calculate effective working interest WI_{ARO}

$WI_{ARO} = (1 - JV_{govt}) \times WI_{operating}$ (1)

⇩

(III) Calculate future value of reported ARO cost

$C_{EOFL} = C_{WI} \times (1 + r)^{n}$ (2)

where "n" is the number of duration in years, from the year of the annual financial report Y_{report} to the end of field life Y_{EOFL}, i.e., $n = Y_{EOFL} - Y_{report}$

⇩

(IV) Calculate ARO cost in money of the day at report year C_{report} and reference Year C_{ref}

a) $C_{report} = C_{EOFL} / (1 + i)^{n}$ (3)
b) $C_{ref} = C_{report} \times U_{index}$ (4)

where $U_{index} = UCCI_{ref} / UCCI_{report}$, $UCCI_{ref}$ is the UCCI index factor for the reference year and $UCCI_{report}$ is the UCCI index factor for the report year

⇩

(V) Calculate 100% WI cost of ARO $C_{ref\_100\%WI}$ for each operator's report and average cost per facility for each operator's report $C_{operator}$

a) $C_{ref\_100\%WI} = C_{ref} / WI_{ARO}$ (5a); $C_{operator} = C_{ref\_100\%WI} / FS$ (5b)
b) $C_{operator} = C_{ref} / (FS \times WI_{ARO})$ (5c), if steps in equations 5a and 5b are combined

⇩

(VI) Calculate ball park rough order of magnitude ARO cost per facility $C_{average}$

$C_{average} = \sum C_{ref\_100\%WI} / FS$ (6), rounded up to \$10 million

⇩

(VII) Calculate aggregate cost of decommissioning for onshore fields in Nigeria C

$C = C_{average} \times \textit{Total number of Existing Flowstations}$ (7)

Figure 41: Methodology for estimation of decommissioning cost from declared cost of ARO

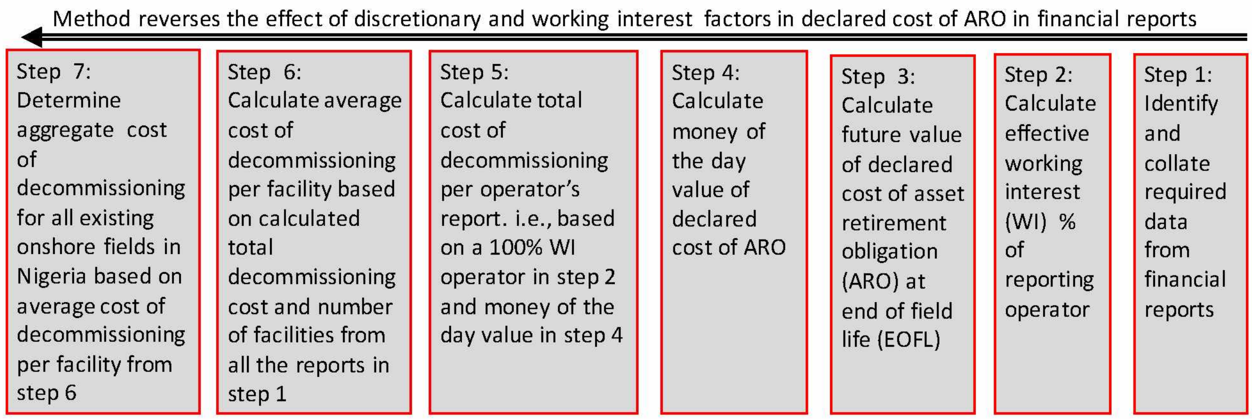


Figure 42: Method for the estimation of decommissioning cost from declared cost of ARO

Nigeria_ARO_Cost_Model is a top-down model with a focus on the determination of the ARO cost for all Nigerian onshore fields at a higher aggregate level and the results can also be used as a basis to estimate the cost of decommissioning per unit of crude oil development or decommissioning scope, which is defined in this study as a gathering or flowstation. Using MS Excel, which the public and local oil producing community stakeholders even in Nigeria can easily acquire, this study presents a model that takes input data from publicly available decommissioning related information to generate a result which is the estimated aggregate cost of meeting decommissioning liabilities for the case study, onshore crude oil fields in Nigeria.

8.6.2.1. Nigeria_ARO_Cost_Model

Applying the methodology in Figures 41 and 42 to Nigerian onshore crude oil fields, Nigeria_ARO_Cost_Model is used for estimating generic costs of decommissioning liabilities for Nigerian onshore fields using ARO data from annual corporate financial reports. The methodology introduced in this study to calculate cost estimates for decommissioning liabilities is basically a reverse of the process used to determine the declared cost of ARO in Figure 29. As illustrated in Figures 41 and 42, the first step is to find the annual financial reports for the new companies that operate in only Nigerian onshore fields. This approach could also be applied to any entity in the world that operates in only in a particular region. Public domains searched include company websites, Nigerian oil industry regulatory agency websites, and public repositories for corporate financial data such as System for Electronic Document Analysis and Retrieval (SEDAR) owned by the Canadian Securities Administrators and Electronic Data Gathering, Analysis, and Retrieval system owned by the US Securities and Exchange Commission. The Nigerian Stock Exchange does not have a publicly accessible repository and some of the companies are not publicly listed. The Bloomberg Terminal, a commercial repository for corporate financial data, was also searched for information (see Appendices A and B). Out of 13 of such companies, 3 were found to have publicly accessible annual financial reports with adequate clarity in declared asset retirement or decommissioning obligations that could be used for decommissioning cost estimation. Between these three companies, there were 11 annual financial reports spanning 2011 to 2015. Each report was taken as a data point. The reports had the assets covered in the decommissioning scope of work clearly delineated, discount rate and inflation rate either clearly stated or able to be reasonably assumed, and the year when the EOFL occurs was also declared. These pieces of information, isolated from the financial reports, become input data for the cost estimation model.

The second step involves identification and isolation of relevant data from the annual financial reports and matching them with the decommissioning scope of work declared in the report. For this study, a flowstation was defined and used as a standard unit or parameter of scope for decommissioning. The financial reports were evaluated to identify the number and size of flowstations "FS" and associated infrastructures that were encompassed in each reported cost of ARO. Most of the onshore fields in Nigeria are operated as a JV partnership, where the government holds a percentage or ratio of the working interest JV_{govt} and an operating company or group of companies hold the remaining working interest percentage, this is, $1 - JV_{govt}$. Therefore, a reporting company may own only a percentage of the remaining working interest. In this study, the working interest $WI_{operating}$ of the reporting company in the operating company was also identified from the reports. The effective working interest ratio or percentage for a field or flowstation's cost of ARO becomes

$$WI_{ARO} = (1 - JV_{govt}) \times WI_{operating} \qquad \text{Equation (11)}$$

The declared cost of ARO "C_{WI}" identified from the financial report is the present value of the portion of the total ARO cost due from the reporting company and is in proportion to its working interest in the flowstation, field, or asset. Other pieces of information identified from the annual reports and used as input data include discount rate r, inflation rate "i," and $EOFL$.

The third step entails the application of the company's discount rate r to bring the declared present value of the ARO "C_{WI}" to the future value C_{EOFL} at the EOFL. For this case study, the discount rates were stated in the annual reports. In the absence of a stated discount rate in the financial report, a weighted average cost of capital can be calculated as a proxy for discount rate. The future value C_{EOFL} of the ARO at the EOFL becomes

$$C_{EOFL} = C_{WI} \times (1 + r)^n \qquad \text{Equation (12)}$$

where n is the number of years from the year of the annual financial report Y_{report} to the EOFL Y_{EOFL}, that is, $n = Y_{EOFL} - Y_{report}$.

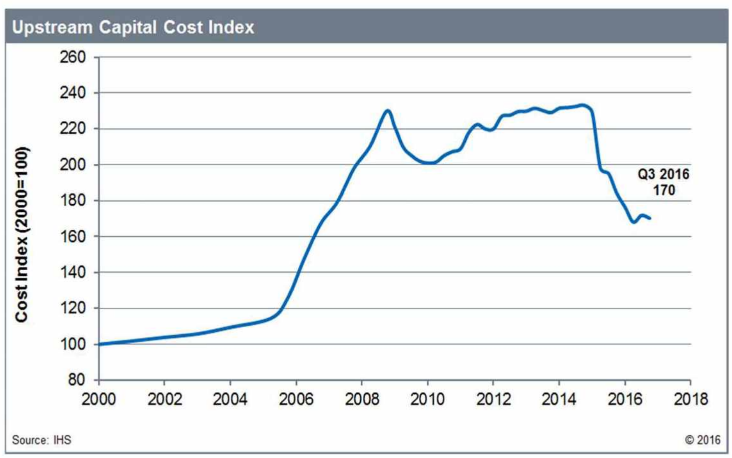
The fourth step encompasses the application of inflation rate "i" to deflate the future value C_{EOFL} back to money-of-the-day ARO cost C_{report} at the year of the annual report Y_{report}. Thereafter, C_{report} is escalated from the report year Y_{report} to the reference year Y_{ref}, using an escalation factor "U_{index}" to obtain the money-of-the-day ARO cost C_{ref} at the reference year Y_{ref} as shown in Equations 13 and 14. The reference year is the year in which the evaluation or study is being done, which was 2016 for this study. The escalation factor U_{index} used in this study was taken from the Upstream Capital Cost Index (UCCI) shown in Figure 43. UCCI is a reputable cost escalation index prepared by IHS/CERA (2016) and is popular in the petroleum industry. An escalation factor was applied because capital costs in the oil and gas industry development have risen due to industry specific business environment and market factors, between the year of the financial report when the declared ARO value was prepared and the year of this study, which was 2016. These changes are captured by IHS/CERA in the UCCI. If the year of the study and year of the financial report happen to be the same, then the application of escalation factor may not be necessary.

$$C_{report} = C_{EOFL} / (1 + i)^n \qquad \text{Equation (13)}$$

$$C_{ref} = C_{report} \times U_{index} \qquad \text{Equation (14)}$$

where $U_{index} = UCCI_{ref} / UCCI_{report}$; $UCCI_{ref}$ is the UCCI index factor for the reference year; and $UCCI_{report}$ is the UCCI index factor for the report year.

There were no inflation rates declared in the annual reports, except for Eland Oil & Gas PLC (2015), which stated that the inflation rate used to adjust its decommissioning obligations was 4.75% in 2014 and 2% in 2015. Rogers & Atkins (2015) noted similar observations with petroleum companies in the United States. They used a proxy of the difference between the long term real interest rate and the long term nominal interest rate to determine the inflation rate, which was 1.5% for several years. In the absence of an operator's specific inflation data, Eland's declared inflation rate of 2% was assumed for other operators. Eland Oil & Gas PLC operates only in the Nigerian crude oil fields. This challenge with information on inflation rates and the potential impact on calculated cost of decommissioning is addressed through a sensitivity analysis in section 9.1.4.



IHS/CERA (2016)

Figure 43: IHS/CERA upstream capital cost index (UCCI)

The fifth step involves using the effective working interest percentage to bring the ARO cost C_{ref} to a total or 100% effective working interest ARO cost $C_{ref\_100\%WI}$, as shown in Equation

15a. To obtain the ARO cost per facility for each operator's report $C_{operator}$, $C_{ref\_100\%WI}$ was divided by the number of flowstations FS in the operator's report, as shown in Equation 15b:

$$C_{ref\_100\%WI} = C_{ref} / WI_{ARO} \qquad \text{Equation (15a)}$$

$$C_{operator} = C_{ref\_100\%WI} / FS \qquad \text{Equation(15b)}$$

and combining Equations 15a and 15b to get Equation 15c:

$$C_{operator} = C_{ref} / (FS \times WI_{ARO}) \qquad \text{Equation (15c)}$$

For this case study, the decommissioning cost per facility from each report $C_{operator}$ was regarded as a decommissioning cost estimate data point. Over the entire data set, the highest and lowest decommissioning cost estimates per facility were identified. This was taken to represent the range of decommissioning costs per facility for onshore fields in Nigeria. HM Treasury and Infrastructure UK (2015), in its guideline for cost estimation for infrastructure projects and programs in the UK, requires "early-stage total project costs to be quoted as estimate ranges rather than single point estimate figures." This recognizes that accuracy of single point estimates at early stages is challenging.

The sixth step entails the calculation of a ROM average ARO cost per facility $C_{average}$ using Equation 16.

$$C_{average} = \Sigma C_{ref\_100\%WI} / \Sigma FS \qquad \text{Equation (16)}$$

The average of the entire data set was determined, instead of finding the average of the respective average decommissioning cost per facility from each report $C_{operator}$. This approach helps to avoid Simpson's paradox of "averaging of averages" (Wagner, 1982; Wainer, 1999; Lesser, 2001). $C_{average}$ was rounded up to the next US$10 million to provide a ROM average cost estimate that is appropriate for the very low level of scope definition. According to Project Management Institute (2013), rounding of cost estimates can be done to a prescribed precision that reflects the size of a project, which in this case is in the order of tens of millions of dollars. This value was taken as the average cost of meeting the decommissioning liabilities for each onshore crude oil field facility in Nigeria. There was no contingency factor applied as none were stated in the reports. It will be consistent to assume that each operator may have applied its own contingency factor to the cost estimate, as considered necessary.

Under the seventh step for this case study, the average cost per facility $C_{average}$ was multiplied by the total number of onshore assets and fields in Nigeria, which was assumed to be 100. The product is the ROM total cost estimate C of decommissioning liabilities for all onshore fields and assets in Nigeria. This cost may be used for policy planning purposes, elicit discussion on decommissioning, and be deemed a reasonable proxy for the total decommissioning liability for all the onshore fields in Nigeria.

Kaiser & Pulsipher (2008) highlighted the limitations of decommissioning cost estimates and noted that they are "only indicative of a general trend related to a condition and should be interpreted as such." According to LaGuardia (1991), "generic cost estimates are important in giving a general impression about magnitude of overall task for decommissioning." Taking into consideration the fact that an aggregate decommissioning cost data for onshore crude oil fields in Nigeria will serve the purpose of providing a general impression of the magnitude of decommissioning liabilities at an aggregate level, a generic ROM cost estimate should suffice. As concluded by Zawawi et al. (2015), in recognizing that there are uncertainties and accuracy limitations in the input data, the objective of the cost model will be "to enumerate a range rather than an exact cost estimate"; and in the absence of a better alternative, it could be used to define "a zone of possible agreement" for negotiations that have to do with accountability for decommissioning and associated environmental liabilities or regulatory decision trade-offs. In a similar direction, it could be inferred from Smith (1991) earlier conclusion that for the intended purpose of ensuring funding for decommissioning liabilities, it suffices to use cost estimates from generic approaches to provide "reasonable bounds."

The results based on publicly available data for Nigeria onshore fields are presented in section 9.1.2

8.6.3. Methodology for the Determination of Vulnerability to Decommissioning Default Risk (DCR and DCRV) for Crude Oil Fields

From the literature review in chapter 7, it was concluded that CDR and ADR do not directly represent the chance of a failure by an operator to meet decommissioning obligations. The connotation that they are risk metrics is not an appropriate description. They are more a reflection of vulnerability to decommissioning default risk. In addition, they do not reflect an entire region's vulnerability to decommissioning default risk, but vulnerability to decommissioning default risk from all of a corporation's assets (which is CDR) or particular assets (which is ADR). Therefore, to reflect vulnerability which this metric directly measures when applied to a region, and to provide it a more generic nomenclature, it is described in this study as decommissioning coverage ratio (DCR). Furthermore, a region or country may have different fiscal elements yielding different streams of revenue. Therefore, the metric will be expressed with respect to a specified stream of revenue as shown in Equation 17. In this manner, it could be more helpful to a government for fiscal planning and policy development purposes. For a county such as Nigeria without a mature regulatory framework for decommissioning of its geriatric onshore fields, the DCR will be a very useful metric. It will set a baseline and measurable indicator for the development of a regulatory policy and implementation plan for decommissioning.

$$DCR = PV\_rr / C \qquad \text{Equation (17)}$$

where ***PV_rr*** is the present value of remaining revenue at an appropriate discount rate and ***C*** is the cost of decommissioning.

It could also be used to determine the amount of additional financial security ***AFS*** required to provide the desired financial assurance against default risk for decommissioning liabilities (Equation 18).

$$AFS \geq (DCR \times C) - PV\_rr - CFS \qquad \text{Equation (18)}$$

where CFS is the financial security currently provided by the company and held by the government.

8.6.3.1. Methodology and Steps to Determine DCR

I. Determine the decommissioning fiscal policy objectives and scenarios of interest. For this case study, the fiscal policy objectives are tax, royalty, JV profit share, and gross operating revenue streams, and the scenarios of interest will be EOFL scenarios.

II. Determine the asset valuation or future production profiles that match the scenarios

III. Determine the present value (PV) of the remaining revenue streams from the future production forecast using stated price, operational cost, discount rates, and other economic factor assumptions.

IV. Determine the decommissioning cost in reference year's money, that is, year of study.

V. Determine the DCR, which is ratio of the remaining revenue streams to decommissioning cost (Equation 16).

Note that both deterministic and probabilistic techniques could be applied to determine the values of remaining revenue used in the calculation of DCR.

8.6.3.2. Further Limitations with DCR as a Vulnerability Metric

DCR is a ratio of PV of the remaining potential revenue to the cost of meeting decommissioning liabilities or ARO at a particular point in time or year. It is a snap shot indicator and has the inherent deficiencies of a one-dimension indicator. It does not provide a pragmatic insight to the vulnerability of government to decommissioning default risk from industry operators. For example, the inter-temporal perspective and timing for release of the risk event cannot be easily interpreted from it.

Field "A": Estimated decommissioning cost *C* is $0.5 million										
Unit of production accounting period	0	1	2	3	4	5	6	7	Total	DCR
Production "Field A" (Mbbls)	0	45	75	75	55	35	15	0.0001	300	
Rev , revenue ($ million) at netback of $10/bbl	0	0.45	0.75	0.75	0.55	0.35	0.15	0.00	3	6
Field "A": cummulative revenue ($million) calculated backward from last accounting period of production	3.00	3.00	2.55	1.80	1.05	0.50	0.15	0.00	***DCR = Total Revenue / C***	
DCR for each period	6.0	6.0	5.1	3.6	2.1	1.0	0.3	0.0	i.e. 300/0.5 = 6	
Period before remaining revenue will no longer exceed decommissioning cost when calculated bacward from last accouting period of production **(The DCRV concept)**	5 more units of production accounting period									

Field "B": Estimated decommissioning cost *C* is $0.5 million										
Production accounting period	0	1	2	3	4	5	6	7	Total	DCR
Production Field "B" (Mbbls)	0	125	125	20	15	10	5	0.0001	300	
Rev , revenue ($ million) at netback of $10/bbl	0	1.25	1.25	0.2	0.15	0.1	0.05	0.00	3	6
Field "B": cummulative revenue ($million) calculated backward from last accounting period of production	3.00	3.00	1.75	0.50	0.30	0.15	0.05	0.00	***DCR = Total Revenue / C***	
DCR for each period	6.0	6.0	3.5	1.0	0.6	0.3	0.1	0.0	i.e. 300/0.5 = 6	
Period before remaining revenue will no longer exceed decommissioning cost when calculated bacward from last accouting period of production **(The DCRV concept)**	3 more units of production accounting period									

Figure 44: Calculation of DCR and cumulative remaining revenue for hypothetical fields

DCR provides an indication of the magnitude of exposure to cost, if the default event occurs. It does not provide an indication of when the event could occur. If two hypothetical fields “A” and “B,” each has a DCR of six for a respective decommissioning liability of $0.5 million, it means that for each field, the remaining revenue is six times the cost of decommissioning liabilities (Figure 44). Assuming a liability management objective of DCR not less than one and considering that the two fields have equal DCR, they may appear to have an equal measure of vulnerability to decommissioning default risk.

However, the profiles of cumulative remaining revenue (Figure 45) show that comparatively, field “B” has less production accounting period before its cumulative remaining revenue will fall to a level equal to or less than the cost of decommissioning liabilities for the field. DCR as a metric for vulnerability to risk does not reflect this aspect of the decommissioning default risk event. In addition, the DCR row in Figure 44 shows that DCR for field “B” in accounting period 3 will be less than one, a significant drop from a DCR of 3 in the immediate preceding accounting period. A field with a less significant exposure in one period has suddenly become a field with significant exposure at the next accounting period. DCR does not provide this pre-emptive information. This scalar interpretation (in analogy to scalar and vector concept in physics) of DCR is one of the deficiencies with a snapshot one-dimension indicator for the evaluation of vulnerability to decommissioning default risk. It provides no sense of imminence or temporal direction of exposure to decommissioning default risk.

8.6.3.3. Introducing Decommissioning Coverage Ratio Vector (DCRV)

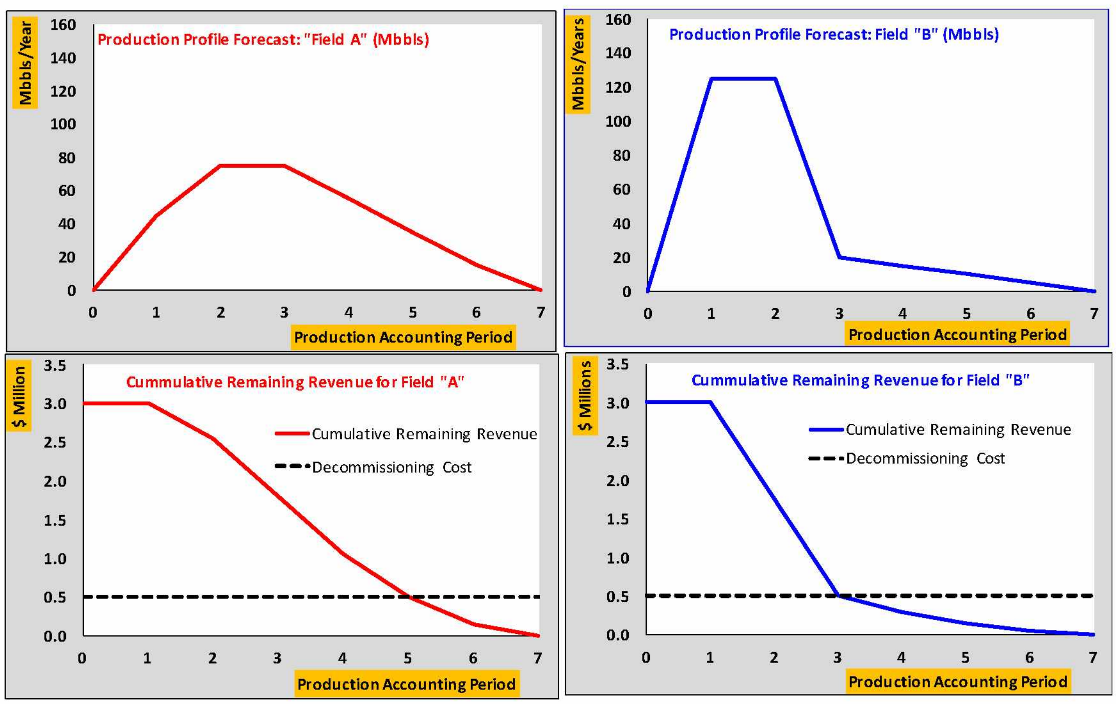


Figure 45: Production and remaining cumulative revenue profiles for hypothetical fields

This study introduces a new decommissioning risk exposure metric that addresses the deficiencies of a snapshot one-dimension indicator for the evaluation of exposure to decommissioning default risk for crude oil fields. The new metric, described as DCRV, uses a timeline-based approach. DCRV requires the generation of credible forecast of production profile for remaining crude oil volumes, associated revenue streams, and layout of the revenue over a temporal scale. It also requires the description of EOFL scenarios. DCRV is a backward collation of the cumulative PV of the remaining revenue stream, and identification of a point along the timeline when the remaining revenue can no longer cover the estimated decommissioning cost.

For the hypothetical field "A," cumulative remaining revenue will no longer cover estimated cost of decommissioning for the field after five accounting periods and similarly for field "B," it is after three accounting periods (Figure 44). This is also reflected in the intercept of the decommissioning cost plot and the cumulative remaining revenue plot (Figure 45). The DCRV for fields "A" and "B" are five and three respectively, even though both fields have a DCR of six. They reflect the remaining accounting period before their DCRs become one, a time when their remaining revenues will become less than the cost of decommissioning liabilities. With the same DCR of six, both fields appear to have equal vulnerability to decommissioning default risk, but the imminence of the risk event and hence urgency to develop a mitigation plan for field "B" with DCRV of three is higher in comparison to field "A" with DCRV of six.

In comparison to DCR, this metric yields a better timing perspective and hence an inference about the urgency for a decommissioning strategy and policy development in a region. Considering that the revenue stream and timeline for crude oil fields are not short-span as modeled in the hypothetical fields, this metric will be easy to use for decommissioning policy development, evaluation, and communication, particularly in a developing nation with immature regulatory capacities such as Nigeria. Complementing DCR, they demonstrate an entity's level of exposure and vulnerability to and the imminence of decommissioning default risk. It can provide information on how fast a region approaches a critical decommissioning coverage position, if it is calculated and monitored periodically. It can also be used for comparison of decommissioning plans amongst fields.

8.6.3.4. Methodology and Step to Determine DCRV

The determination of DCRV requires another step further from step III of the DCR model, which presents the revenue stream in a time line profile.

I. From EOFL (based on scenario descriptions in step 1 of DCR model), do a backward pass on the cumulative revenue row to determine the accounting period when the cumulative remaining revenue equals the decommissioning cost (i.e., when DCR=1). The number of accounting periods before a DCR = 1 occurs, is the DCRV (Figure 45).

8.6.3.5. Nigeria_DCRV_Model: Application of DCR and DCRV Methodologies for Onshore Fields in Nigeria

A third model "Nigeria_DCRV_Model" for determination of metrics for vulnerability to decommissioning default risk and the imminence of its occurrence will be developed for onshore fields in Nigeria using the methodology described in section 8.6.3 (Appendix C). This model will combine several other factors with results from Nigeria_Onshore_Production_Decline_Model and Nigeria_ARO_Cost_Model. This model will be used to test the behavior of different government's revenue streams from the onshore crude oil fields within the decommissioning/fiscal policy framework to determine vulnerability to decommissioning default risk and the imminence of its occurrence in Nigerian onshore crude oil fields.

Currently, there are no good indicators to demonstrate that decommissioning of onshore crude oil fields in Nigeria is becoming an imminent problem. This study calculates DCR for Nigeria and develops a new decommissioning risk exposure metric, DCRV that addresses the deficiencies of a snapshot one-dimension indicator associated with DCR. It demonstrates the imminence of decommissioning for onshore fields in Nigeria.

As a demonstration of the methodology, DCR and DCRV models were prepared for onshore crude oil fields in Nigeria and used to evaluate if the region has a problem with decommissioning that needs immediate reaction. This method can be prescriptively applied or revised for decommissioning policy development in any other crude oil producing region or field.

Step Ia: Decommissioning Fiscal Policy Objective – Royalty, JV Profit, Tax, and Net Operating Profit Revenue Streams

The revenue streams and fiscal policy elements of interest for decommissioning, particularly with respect to fields in Nigeria are the remaining tax revenue, royalty revenue, and JV profit share revenue. In situations where the government is in charge of the field operations, the gross revenue less all expenses (i.e., the net operating revenue) becomes the revenue stream of interest. These revenue streams of interest will be evaluated under different scenarios to determine the susceptibility or vulnerability of stakeholders to decommissioning default risk.

However, more significant attention will be provided to the remaining tax revenues as tax revenue is a representation of the efficiency of operations and how it benefits the recipient generation while operating the assets. From an intergenerational perspective, it becomes the most appropriate revenue stream to use in paying for or setting aside funds to pay for decommissioning of assets, which the future generation may not commensurately enjoy. Therefore, the most significant decommissioning fiscal policy objective for the case study is adequacy of remaining tax revenue stream from onshore fields to support their decommissioning.

The fiscal system for onshore fields in Nigeria is a JV arrangement, unlike the offshore fields that are mostly under PSC. The GT is the total of all revenues that accrue to the government from the crude oil, irrespective of the mechanism of collection. In a JV arrangement, the GT is the sum of revenues from the fiscal policy elements such as signing bonuses/fees, royalties, JV profits, taxes, and sundry fees. Royalty is not a measure of operational efficiency as it is collected as an excise tax on the crude oil produced on the surface. It is not significantly sensitive to oil price as it is usually based on per volume extracted to the surface. The JV profit is the government's share in profits from the operations. It is in proportion to the government's working interest in the field. This revenue stream can go away if the government decides not to participate in the JV arrangement. It may not always be available to the government. Taxes are based on the profit made by oil companies. This stream of revenue is available until the end of a field's economic life. Tax is the reliable source of revenue to the government and benefits from operational efficiency. From intergenerational equity perspective, it is a reflection of the executing generation's efficiency at managing the natural resource.

As each generation ought to manage the liabilities they create, tax revenue stream will be a good candidate for the management of decommissioning liabilities by the beneficiary generation. Using tax revenue, the government may set aside funds to provide tax credits to operators who completed decommissioning projects effectively in the future or to directly pay for decommissioning liabilities, if an operator defaulted in its decommissioning obligations.

Step Ib: Scenarios Creation and Description

This step involves the application of scenario planning "to gather and transform information of strategic importance into fresh perceptions" (Wack, 1985). While the exact method and time that the EOFL may occur is uncertain, the availability of financial and technical resources to properly complete decommissioning activities will be the most impacting primary factors and priorities that will influence decisions on sustainable decommissioning of these fields. Leveraging these priorities, and uncertain methods and time of EOFL, analogous end of life pictures of the future for decommissioning can be sketched as distinct and different plausible future outcome scenarios for decommissioning. Scenarios, according to Schwartz (1996), are "stories that can help us recognize and adapt to changing aspects of our present environment. They form a method for articulating the different pathways that might exist for [ ] tomorrow, and finding [ ] appropriate movements down each of those possible paths." An end of life theme describing how death could occur, was used to develop decommissioning scenarios for Nigerian onshore crude oil fields. The results are presented in chapter 9.3

Step II: Remaining Production Profile Forecast – Nigeria_Onshore-Production_Model

Under this step, a production forecast of remaining future production profile corresponding to each described future scenario for the region is determined. For this study, this will be based on the production decline model ***Nigeria_Onshore-Production_Model***, described in section 8.6.1 and results in chapter 9.1. For deterministic analysis, aggregate production forecast results based on exponential and harmonic decline curve methods for each scenario will be determined for onshore fields in Nigeria, while for probabilistic analysis, the hyperbolic decline curve method is used.

The following three steps (steps III, IV, and V) were applied to both the deterministic and probabilistic cases for each future decommissioning scenario and revenue stream of interest for Nigerian onshore crude oil fields.

Step III: Present value (PV) of the Remaining Revenue (Tax Revenue)

This step determines the value of the remaining production prolife that could serve as collateral coverage for decommissioning under each scenario. Deterministic models (Figure 46) were developed to determine the PV of the different remaining revenue streams from Nigerian onshore fields. They were based on the three selected decommissioning scenarios, the three price cases, the two DCA based production forecast in step II, assumed production cost, discount rate, and applicable royalty and tax rates.

$Revenue = q_t \times 365 \times P_c$ Equation (19)

$Royalty = q_t \times 365 \times R \times P_c$ Equation (20)

$Prod\_Cost = q_t \times 365 \times C_{per\_bbl}$ Equation (21)

$Taxable\_Profit = Revenue - Royalty - Prod\_Cost$ Equation (22)

$$Cum\ PV\_tax\ revenue = \sum_{i=Ref\_year}^{n} (Tax\_rate \times Taxable\_Profit) \,/\, (1 + r)^{(n-Ref\_year)}$$ Equation (23)

where ***Revenue*** is the total revenue from crude oil; ***Royalty*** is the royalty collected by the government from extracted crude oil based on rate set by government; ***Prod_Cost*** is the total production cost; ***Taxable_Profit*** is the portion of revenue available for tax; ***Cum_PV_tax_revenue*** is the cumulative PV of tax income; q_t is the rate of crude oil production in bbl per day; P_c is the price per barrel of crude oil; C_{per_bbl} is the marginal production cost per barrel; ***Tax_rate*** is the tax rate set by the government to be applied to taxable profit; r is the selected discount rate; ***Ref_year*** is the reference year or year of study; and n is the EOFL, a selected in euthanasia scenario or when ***Taxable_Profit*** becomes negative under the graceful death scenario.

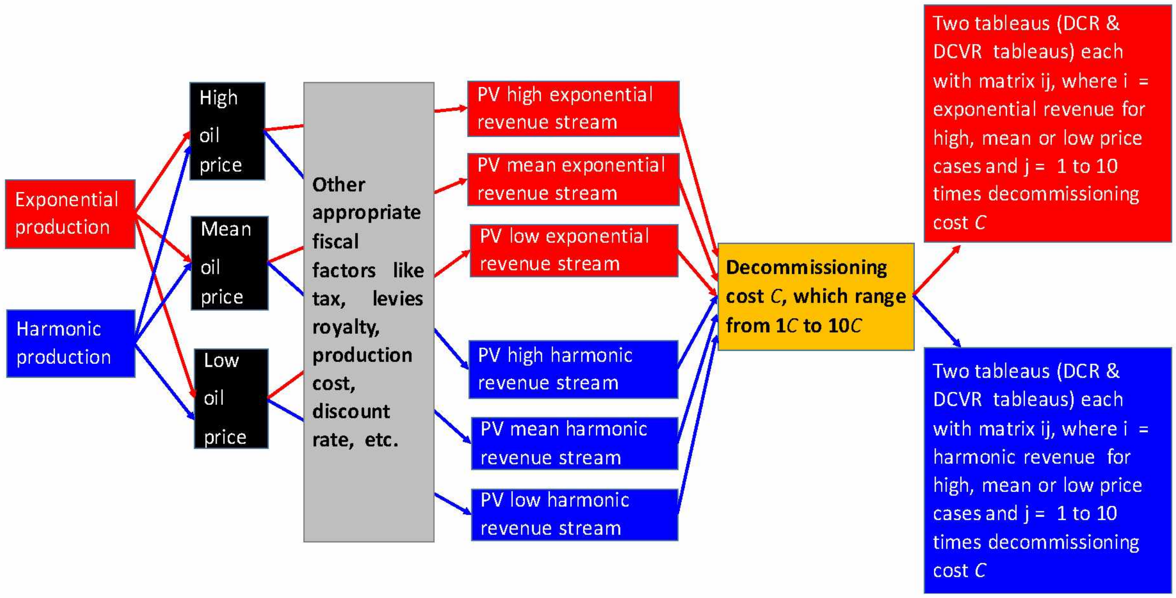


Figure 46: Deterministic model for a revenue stream under each decommissioning scenario

Considering a sensitivity analysis to the deterministic results, two probabilistic models, one for each scenario were also prepared for the remaining tax revenue streams from the onshore fields in Nigeria. For stochastic evaluation, production forecast was based on hyperbolic decline curve method (Table 5) with the hyperbolic exponent b, randomly varied between 0 and 1, and the price $\boldsymbol{P_c}$ randomly varied between the low and high price cases. This was used to evaluate the confidence around the deterministic valuation results. With the steady, long post peak production period and for high level policy decisions for a region, stochastic evaluation within the boundary range of price and hyperbolic exponent will provide adequate spread of information for probabilistic analysis; hence, decline rate D_i and initial production q_i were not varied randomly.

Step IV: Cost of Meeting the Decommissioning Liabilities

The cost estimate for decommissioning liabilities is maintained confidential by operating companies. Even though financial reporting standards compel companies to declare their decommissioning liabilities, the reporting formats are fraught with ambiguity. Mature regulatory agencies such as the BOEM in the United States and DECC in the UK, do attempt to prepare their own cost estimates. However, with information asymmetry on the scope of decommissioning in favor of operating companies, the cost estimates prepared by the regulatory agencies have significant uncertainties associated with them. There have been efforts to develop credible cost estimates from publicly declared decommissioning liability cost data (Kaiser, 2015a; Kaiser and Liu, 2014). The process of determining the declared cost of ARO in company's financial reports (McEown, 2017; Rogers & Atkins, 2015) can be reversed as outlined in section 9.1 to recreate the current cost of decommissioning liabilities for an entity. For the case study, Nigerian onshore crude oil fields, the results from the Nigeria_ARO_Cost_Model (Figure 41) will be used for this step. This will be used to calculate the DCR for Nigerian onshore oil fields in step V.

Step V: Decommissioning Coverage Ratio (DCR) for Nigerian Onshore Fields

DCR was calculated based on the PV of the remaining revenue for each of the selected revenue streams under high, medium, and low oil price cases, and a sensitivity range from one to ten times the estimated cost of decommissioning (Equation 24).

$$DCR_{\_revenue\_stream} = Cum\ PV_{\_revenue\_stream} / (k \times C) \qquad \text{Equation (24)}$$

where k is a factor 1 to 10 applied to provide multiples of decommissioning cost.

The results will be presented as tableaus DCRs for a matrix of different oil price cases and cases of cost of decommissioning (Figures 48 –71). Kaiser (2015a) presented a similar tableau of asset coverage ratio (ACR) for offshore field assets in the GOM. Kaiser & Liu (2014) also prepared a similar tableau of coverage ratio for some assets in the GOM based on three cases of oil price and sensitivity range of one to five times the cost of decommissioning. The United States has a more mature decommissioning policy and experience in comparison to Nigeria. The cost data and scope are more defined in the United States in comparison to Nigeria. A decommissioning cost sensitivity range from one to ten is expected to provide a wider spread of information to the government and stakeholders for decision making in regions with less mature decommissioning policy frameworks, such as Nigeria. The elements of a tableau of three cases of crude oil prices and the sensitivity range of one to ten times the current estimated cost of decommissioning are assumed to represent DCR data points with equal chances of occurrence (Kaiser, 2015b). Therefore, the average DCR for each tableau of deterministic case is also the expected value of DCR for that tableau. For Nigerian onshore crude oil fields, this will be tested for each of the identified government revenue streams, tax revenue stream (Figures 48–55), JV profit revenue stream (Figures 56 – 63), and royalty revenue stream (Figures 64 –71).

Kaiser & Lui (2015), and Kaiser (2015b) used a reserve to cost of decommissioning liabilities ratio of one as the threshold for GOM. AER and BCOGC used a similar threshold ratio of one for Alberta and British Columbia regions in Canada, respectively. However, at Alberta, Canada, with similar onshore fields such as Nigeria, but more mature decommissioning regulatory frameworks, Alberta Energy Regulator (2016) requires a minimum coverage ratio of 20 for problem sites and fields undergoing divestment. With the legacy of notorious environmental degradation problems and ongoing divestment by MOCs to smaller companies, Nigerian onshore crude oil fields could be comparable to Alberta's problem sites.

Decommissioning projects in the UK and the United States have seen significant cost over-runs, up to a 100% cost over-run in some cases (Oudenot et al., 2017). Therefore, this study assumes the threshold for onshore fields in Nigeria to be a DCR greater than 20. The vulnerability represented by an expected value of DCR greater than 20 is considered a low vulnerability to decommissioning default risk. DCR between 10 and 20 represents a medium vulnerability condition and DCR less than 10 represents a high vulnerability condition. This was selected to reflect uncertainties associated with the cost estimate due to lack of defined standards and scope for decommissioning in Nigeria, legacy environmental issues, and empirical trends of cost over-run for decommissioning projects.

Step VI: Moving from DCR to DCRV – The DCRV Model

In this step, the DCRV is calculated. For each decommissioning scenario, starting from the EOFL year, the cumulative PV of the remaining tax revenue will be calculated in a backward time sequence until the reference year. Using the decommissioning cost estimate, C, the coverage ratio for each year will be determined, sequentially back to the reference year, which for this study is 2016. Starting from the reference year, the number of years before remaining revenue declined to a level where it can barely cover the decommissioning liability will be determined. This is the DCRV for that particular deterministic case. It represents the length of period or time between the reference year and the year when DCR becomes less than one, which is a measure of how imminent production could decline to a situation where the remaining generated revenue could become insufficient to cover decommissioning liabilities.

Interpreting the results, a DCRV of 30 connotes approximately 30 years before the remaining cumulative tax revenue will be less than the decommissioning cost for the onshore fields. Due to the bureaucratic process and delays with public policy development and implementation in Nigeria, particularly where it is related to public revenue at the federal level, 30 years will be a reasonable lead time for decommissioning policy development, planning, and implementation. Since 2000, Nigeria has been struggling to enact a new petroleum industry development bill aimed at boosting growth in the industry (Erunke, 2016). Another precedence is the Ogoni field's decommissioning plan that is expected to take 30 years. The plan which commenced in approximately 2006, after Shell's forced exit due to sociopolitical crises in the late 1990s, is supported by the United Nations, but until 2017, execution was yet to commence (Osibanjo, 2017).

A DCRV of 30 or below will be a critical situation with high urgency to commence decommissioning policy development and plans. DCRV of 40 represents a comfortable decommissioning policy development lead time of 40 years and a low urgency situation. A DCRV between 30 and 40 will be a situation with moderate urgency to commence decommissioning policy development and plans in Nigeria.

8.6.3.6. Other Input Data Assumptions

Production Cost (C_{per_bbl}): Nigerian crude oil production cost per barrel was $28.99 in 2016 ("Barrel breakdown," 2016). While this production cost data was not clearly described as data for onshore crude oil fields, a breakdown provides 14% as gross taxes. Offshore fields normally have a higher cost in comparison to onshore fields. Knoema (2016), another crude oil production data source, puts the production cost per barrel for offshore fields in Nigeria at $30 and onshore fields at $15. Assuming a proportional gross tax, the marginal production cost per barrel for onshore fields will be $13 per barrel, which was used in the models.

Production Operational Efficiency: This study assumed an annual increase of 1% in the cost of production for the entire field life, considering that these are mature fields with operational challenges. A sensitivity analysis was undertaken with 0.85% and 1.15% annual increase in the cost of production. This represents a 15% change in the rate of annual increase in cost of production, which is also a proxy for low cost and high cost producers, respectively.

Crude Oil Price (*P_c*): Crude oil prices were taken from the World Bank study (World Bank, 2016). Simple descriptive statistics for a 10-year period price forecast provided the high, mean, and low price cases and were assumed for the entire field life duration in the models (Table 8).

Table 8: Crude oil price cases

World Bank Forecast: Assuming the price forecast to be a normal distribution with a standard deviation														
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	**Mean**	**Standard Deviation**	**Low**	**High**
$/BBL	43.3	55.2	59.9	62.7	65.5	68.6	71.9	75.3	78.8	82.6	**66.38**	11.77	**43.3**	**82.6**

Tax Rate: The petroleum profit tax for onshore fields in Nigeria is 85% for JV operations, excluding quasi-taxes such as education tax and Niger Delta development levy (National Petroleum Investment Management Services, 2016). As a proxy to capture the quasi-taxes and levies, a 90% profit tax rate was assumed in the models. The tax rate was applied to taxable income to determine tax revenue.

Royalty Rate (*R*): The royalty rate is set by the government and applied to the total volume of crude oil extracted at the point of extraction (Equation 20), irrespective of the operating profit or loss. In this study, it was 20% for Nigerian onshore crude oil fields (National Petroleum Investment Management Services, 2016).

Discount Rate: A 10% discount rate, which is the rate most commonly used for petroleum investment analysis, was adopted in the models (Kaiser, 2015a; 2015b).

8.6.4. Methodology for the Determination of Sustainable Decommissioning Frameworks Maturity Level for Petroleum Fields

The maturity model methodology has been widely used in several disciplines, business process improvement studies, and complex system problem evaluation/solving studies (Kohlegger et al., 2009; Mettler, 2011). Unger et al. (2015) used a similar approach to develop a jurisdictional maturity model for risk management, accountability, and continual improvement of abandoned solid mineral remediation programs in Australia (Figure 38). Maturity models are very useful for benchmarking, evaluation, and continuous improvement. The different progressive levels of maturity are defined and graded by empirical observation and normative aspirations of desired maturity levels. For sustainable decommissioning in the petroleum industry, this will be through the practices amongst regions and similar natural resource industries with leading experiences in decommissioning and abandonment.

From literature investigation, it was identified that there are few variations to methodology used to develop maturity models. However, primarily, the methodology involves defining the scope and objective of the maturity model, that is, the discipline, issue, or process it intends to cover, breaking the objective into elements which are further defined to “represent desirable properties or dimension of value” (Röglinger et al., 2012), testing the model and deploying it for intended use. de Bruin et al. (2005) elaborated a six-phase approach to maturity model development. Phase 1, scope, involves setting the scope the model will cover, while phase 2, design, involves determining “a design or architecture for the model” showing the audience, method of application, driver of application, respondents, and where it will be used. Phase 3, populate, involves developing the required content which are the attributes and properties that define various levels of maturity in the model, while phase 4, test, involves testing the model using a control sample population to validate the “reliability and generalizability” of the model. Phase 5, deploy, involves its actual usage and phase 6, maintain, is for continuous improvement that are triggered by feedback from its use during phase 5. For an exploratory effort to develop a maturity model for sustainable decommissioning of petroleum fields, phases 5 and 6 may not be applicable at this stage. The model needs to be developed first, before it is improved or maintained.

Furthermore, there are similar maturity levels, established practices, and elements albeit disparate that “represent desirable properties or dimension of value” for decommissioning and abandonment of natural resource development projects. Unger et al. (2015) developed a jurisdictional maturity model that amongst other methods relied heavily on extensive literature investigation and web-based survey. de Bruin et al. (2005) agreed that maturity stages or levels can be defined either through a bottom-up or top-down approach. With a bottom-up approach, "the requirements and measures are determined first and the definitions are written to reflect these" and it is suitable for "where there is existing evidence on what represents maturity." In a top-down approach, "definitions are written first, then measures developed to fit the definitions" and it works where "domain is relatively naïve" and what represents maturity is not very well defined.

For decommissioning of petroleum fields, it will be a combination of both approaches. For some elements, there are evidences of what represents maturity in some regions such as Alberta, Canada and GOM USA, and a bottom-up approach may be suitable. However, for others, a top-down approach may work as the definition of these elements are normative and currently naïve. Following de Bruin et al. (2005) approach, the scope of this maturity model is sustainable decommissioning frameworks for the petroleum industry and the audience will be mostly public stakeholders, government agency personnel, and the petroleum industry practitioners. As this audience varies in their level of competence and awareness about the subject and this study is exploratory, its content will need to be simple and prescriptive. de Bruin et al. (2005) agreed that "a model that appears too complicated may limit interest or create confusion" and "raises potential for incorrect application resulting in misleading outcomes." Therefore, in populating content for the model, the first step is to identify the key elements of sustainable decommissioning frameworks, which are further defined to "represent desirable properties or dimension of value" (Röglinger et al., 2012). Using a combination of bottom-up and top-down approaches depending on the elements, maturity stage or level are then set and defined for the model and for each element of the model. Normative aspirations would also be used to define higher level maturity for some elements that have a relatively naïve definition at a higher level of maturity.

Using this methodology, a graded scale maturity model described as “Fairbanks Maturity Model for Sustainable Decommissioning of Petroleum Fields” or “Fairbanks maturity model” that can be used for benchmarking, progressive evaluation, and monitoring of a region or entity’s level of preparedness for decommissioning of its petroleum fields, will be developed. It will be tested using a comparative analysis between regions with information on as-is status of sustainable decommissioning frameworks in their petroleum industries and its use will be demonstrated with Nigerian onshore crude oil fields as a case study. The maturity model will identify the key elements of a sustainable decommissioning policy or preparedness framework, and define, characterize, and calibrate their attributes into different progressive levels of maturity, using practices from leading regions and normative aspirations deduced from the investigations in this study as presented in the preceding chapters.

8.6.4.1. Key Elements and Evaluation Attributes for a Sustainable Decommissioning Framework for Petroleum Fields

There are few interregional comparative studies on disparate elements of decommissioning in the petroleum industry (Abraham, 2002; Okello, 2013; Fam et al., 2017). From the literature review and investigations in this study, a list of critical elements (Figure 47) which can be used as evaluation criteria for the maturity of a decommissioning policy framework and preparedness for decommissioning in a region, can be identified. They are (i) management of inventory of fields and all associated facilities that will be decommissioning; (ii) defined cost estimate for decommissioning liabilities and ARO for the fields and all associated facilities; (iii) petroleum production data – historical and future volume estimates; (iv) provision for financial assurance; (v) management of vulnerability to decommissioning default risks and decommissioning scope volume ; (vi) management of post-decommissioning liabilities; (vii) regulations and regulatory capacities, and (xi) stakeholder engagement.

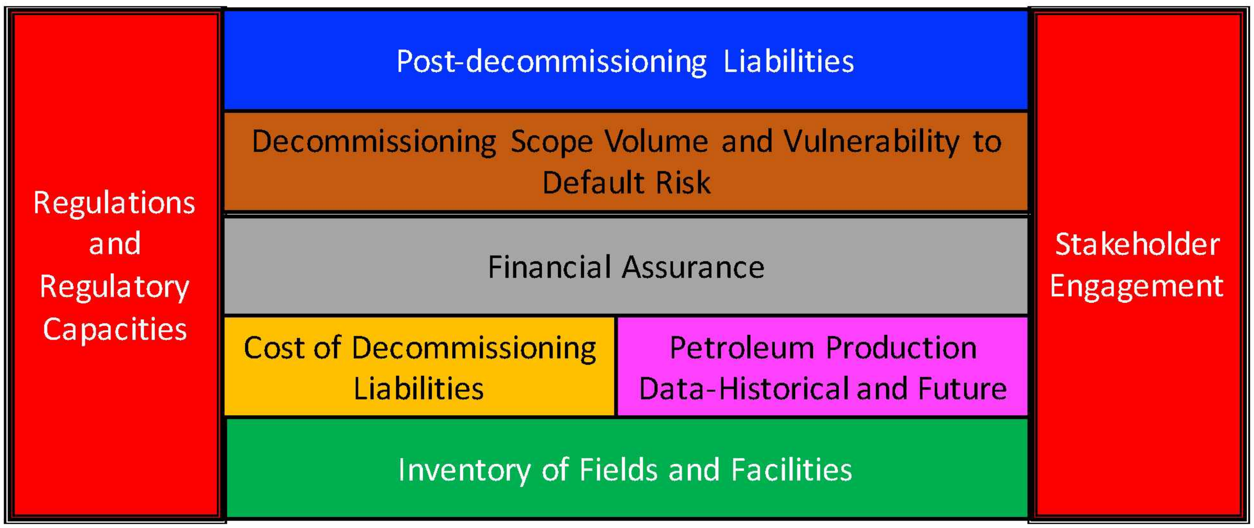


Figure 47: Important elements for a sustainable decommissioning framework

Inventory – Facilities/fields inventory and data management

This criterion requires a decommissioning policy, plan, or program to have a dynamic knowledge of all the fields, facilities, and their pertinent parameters for proper decommissioning. The pertinent parameter will include the location, size, year of installation, records of all operators over the life of the assets, history of major upgrade and changes, and as-built drawings. These pieces of information should be in the public domain, preferably the responsible regulatory agency's website. They should be updated as changes are made (Table 9). Alberta Energy Regulator has already attained this standard. By adopting this method, stakeholders will have limited barriers or challenges to accessing this information which will motivate them to have informed engagement with the government, regulatory agencies, and oil companies as a step toward sustainable decommissioning. This criterion is foundational – stakeholders must know the size of their exposure. Unger et al. (2015) included a similar element in the jurisdictional maturity model for risk management, accountability, and continual improvement of abandoned solid mineral remediation programs in Australia. This will proactively reduce the problem of the identification of orphan wells and responsible parties as currently experienced in Pennsylvania, United States where only 11,872 orphan wells have been located by the government since 1989, even though it is estimated that approximately 560,000 orphan wells are yet to be identified (Department of Environmental Protection, 2017a; 2017b)

Cost – Cost of decommissioning liabilities management

A resilient decommissioning policy or plan will have a methodology for dynamically estimating the cost of all decommissioning liabilities for all facilities and fields under its scope. The cost estimate will be based on the realistic situation, where the government is the executor of the decommissioning projects. This is appropriate because if the operators fail to meet their decommissioning obligations, the government will have to complete the execution. It is expected that the cost estimate will be revised regularly to capture changes and be vetted by a third party or subjected to some reliable quality assurance process. The cost estimate will also be publicly accessible and interpretative to empower public stakeholders to effectively participate in the decommissioning policy and planning process (Table 10). Alberta Energy Regulator is relatively ahead in meeting this objective.

Production decline – Production decline and collateral management

A decommissioning policy, plan, or program is expected to provide dynamic information on the remaining exploitable production volumes from the asset(s) and some indication of the anticipated rent (Table 11). The public should know the prize for which they are exposing the commonwealth. If the public should judge the prize to be non-commensurate, they could then put pressure on the government and regulatory agencies to take mitigation actions. On the other hand, if they judge the prize to be commensurate, they could encourage further progress in the current direction of development of the natural resource. The state of Alaska in the United States has already attained this standard by annually publishing the crude oil production forecast for its oil fields in the DNR website.

Vulnerability – Decommissioning default risk, and vulnerability metric and management

A normative aspiration for a decommissioning policy or plan is that the stakeholders should be able to view a metric or indicator(s) that will at any time, provide them a good reflection of their susceptibility to carry the burden of the decommissioning liabilities from the petroleum fields (Table 12). Expectedly, this will be due to an operator's failure to fully complete its decommissioning obligations, and the inability of the legal and regulatory process to hold such an operator accountable. While there could be benefits in delaying decommissioning of assets until a critical mass or appropriate time for optimal benefits of economics of scale, experience has shown that if not incentivized, operators will prefer to defer spending money on decommissioning. Furthermore, when circumstances compel them to exit a field, the huge bill for decommissioning will become a problem inhibiting asset transfer or could ultimately fall on the government to bear, if they go bankrupt. A sustainable approach to decommissioning will incentivize operators to “clean as they go” by incrementally evaluating their portfolio and completing decommissioning for the uneconomic assets. The best practice will have evidence of consistent and incremental completion of decommissioning for uneconomic assets that can be represented in a vulnerability metric to decommissioning default risk. The metric should be accessible, easy to interpret, and regularly updated. Alberta Energy Regulator, BCOGC, and BOEM have some proxy metrics, but this study has developed a more representative vulnerability metric – DCR and DCRV, introduced in this study for a region or entity.

Post-decommissioning – Management of post-decommissioning liabilities

A salient decommissioning plan will hold all historical or current operators, severally and collectively liable into perpetuity (Table 13). This is the leading practice as operated by OGA and BEIS in the UK. It is a more assured way of shielding the public from eventually paying for the cost of decommissioning liabilities and encourage all operators either those selling or purchasing operatorship rights to undertake due diligence before transfer of assets. Considering the legacy of post-closure socioeconomic condition of mining areas, it is pertinent to call out a need for comprehensive considerations for not only the environmental and health conditions, but the socioeconomic condition of the crude oil producing area after the decommissioning phase. Sustainable development expects the crude oil producing area to not be left worse than it was met in terms of environmental, health, and socioeconomic aspects. For abandoned mines in Australia, Unger et al. (2015) also considered this element and ARUP (2017) considered it as part of recommendation to Brazil’s National Agency of Petroleum, Natural Gas, and Biofuels (ANP).

Financial assurance – Exposure management

A salient decommissioning policy framework is expected to provide complete assurance to public stakeholders that they are shielded from paying for any cost of decommissioning liabilities emanating from the petroleum fields (Table 14). While there are several mechanisms and instruments that can be selected to provide financial assurance, the policy objective will be to ensure that public funds are not used to pay for decommissioning liabilities. This is in line with the polluter pays principle of natural resource economics and management of externalities. AER and BCOGC in Canada, BOEM in the USA, and OGA in the UK have some leading practices for this decommissioning objective, even though they differ in the combination of these instruments.

Stakeholders' engagement – Legal rights, and capacity for and management of stakeholders' participation

As elaborated in this study, stakeholder engagement is closely related to the legal mineral rights held by public stakeholders in a region. While this is a perception criterion, it could also be tangibly evaluated based on the existing legal mineral rights held by private citizens in a region. The aspiration will be for private citizens to have ownership rights, which will incentivize them to be actively and effectively involved in the decommissioning policy and planning process (Table 15). This will also make it easy for them to gain requisite information on decommissioning without the challenges of information asymmetry. Once sufficient private citizens have the information, the public will eventually obtain the information, unlike the situation with information asymmetry where only the government and oil companies have de-jure ownership rights, and therefore access to information on decommissioning. Considering that international regulatory frameworks do not apply to most onshore fields and that most developing nations do not have a private mineral right regime for petroleum resources, the EIA process, if distinctively crafted for the decommissioning process, will be a unique process to incentivize effective stakeholder participation

Regulatory landscape – Regulatory capacity and clarity of regulations

For a salient decommissioning policy and plan, the regulatory agencies responsible for decommissioning of petroleum facilities should be clearly designated, either one or two and independent (Table 16). This will remove ambiguity and lapses in the enforcement of regulatory policies. The regulations should also be very clear and for developing countries, it should be prescriptive. This will remove the problem of slack, which has been identified as a contributory factor to ineffectiveness of regulations (Abraham, 2002) and even more so in developing countries. ARUP (2017) also identified the importance of effective regulatory regimes to decommissioning of oil and gas facilities in Brazil.

8.6.4.2. Fairbanks Maturity Model for Sustainable Decommissioning Policy Frameworks for Petroleum Fields

Based on the relative comparison of decommissioning practices amongst different regions under each of the identified elements, investigations of normative aspirations from literatures, maturity model developed for other disciplines, and the maturity model developed for management risks in abandoned mines in Australia, a sustainable decommissioning maturity model was developed as shown in Figure 48. These identified critical elements, attributes, and characteristics of a sustainable decommissioning framework (Figure 47) were translated into a maturity model for benchmarking and gap analysis purposes, which will further support the drive toward a sustainable policy development.

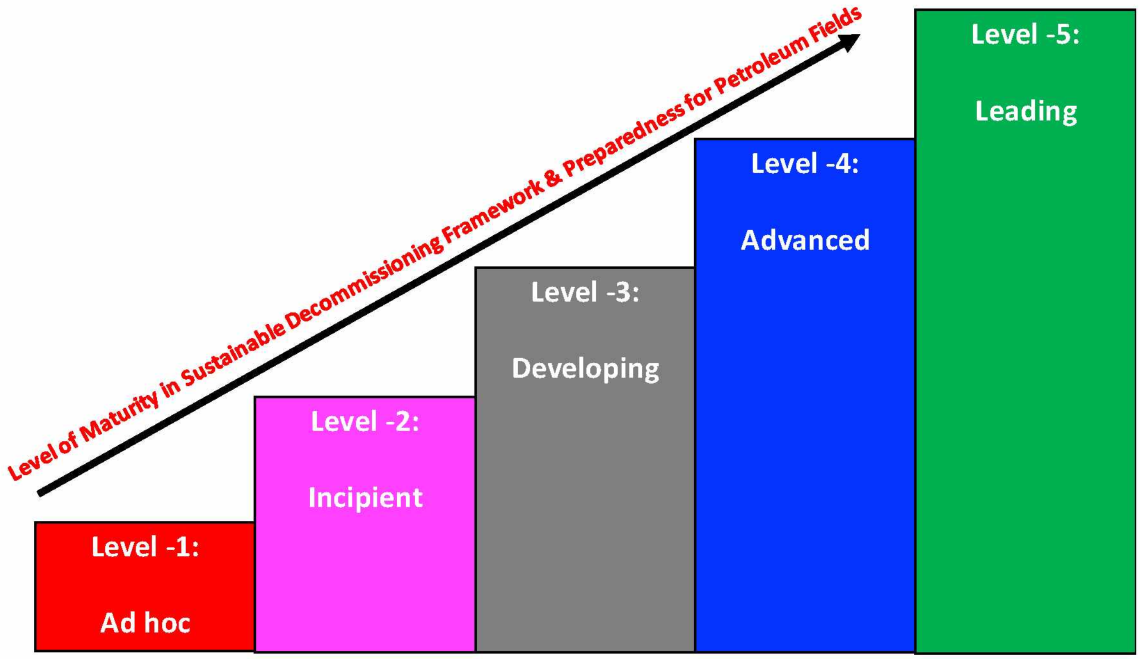


Figure 48: Fairbanks graded scale maturity model

The model has five levels, Level-1 ad hoc, Level-2 incipient, Level-3 developing, Level-4 advanced, and Level-5 leading maturity level. Each of the elements of the sustainable decommissioning framework has different levels of maturity described by the attributes and characteristics (Figure 48), and further elaborated in Tables 9–16. This will be applied to Nigerian onshore fields for gap analysis, and a comparative analysis between countries that are already executing decommissioning activities for their oil fields will help to set and define the relative maturity levels. For this study, as-is information on decommissioning in the regions were collected from publicly accessible domains, such as the regulatory agency and government's website.

In defining graded maturity scale for the financial assurance element in Figure 49, it could be argued that a financial assurance management element that accepts only cash or surety from financial institutions of repute, such as AAA rating, will provide a better assurance than where a combination of self-insurance by the operator, cost, and surety are acceptable. However, others may argue that the former ties down cash that could have been invested in field development. This maturity model deliberately does not consider proprietary of the financial tools themselves, but whether they exist, are updated, and publicly accessible. The premise is that if the public can access reliable data on the status of financial assurance, they can be effectively engaged in public discussions, ask questions, and drive the regulatory agencies and regulations toward the arrangement of financial assurance tools that may be most preferred for the region.

For the management of scope element, it is also assumed and expected that if regular update of the asset/liability ratio is made, published, and managed to ensure it is not below one, the operators will be incentivized to progressively, incrementally, and properly complete decommissioning of uneconomic fields instead of continuously postposing their completion into the future. The state of California in the United States requires operators to submit an idle wells management plan annually, demonstrating that it will properly complete abandonment of 4–6% of its inventory of idle wells each year, else will pay a fine per well each year (Division of Oil, Gas and Geothermal Resources, 2018).

Table 9: Attributes used for evaluation of graded levels of maturity in management of inventory of assets in a sustainable decommissioning policy framework for the petroleum industry

	Maturity Level / Element	Level 1 Ad hoc	Level 2 Incipient	Level 3 Developing	Level 4 Advanced	Level 5 Leading
1	**Inventory of assets:** Attributes that describe different maturity levels in management of inventory of assets in a sustainable decommissioning framework	A decommissioning register or asset/facilities inventory do not exist (for this case study, by free public access to the website).	A decommissioning register or asset/facilities inventory is known to exist but must be requested from the regulatory agency. There is no free public access to it.	A decommissioning register or asset/facilities inventory is publicly accessible for free and has the assets recorded at a higher aggregate class without granularity, but it is not regularly updated (at least not done annually).	A decommissioning register or asset/facilities inventory (i) is publicly accessible for free, (ii) has the assets recorded at a higher aggregate class without granularity, and (iii) is regularly updated (at least annually).	A decommissioning register or asset/facilities inventory (i) is publicly accessible for free, (ii) contains the individual field and well names, location, year of installation, size, and the operational status, and (iii) is regularly updated (at least annually).

Table 10: Attributes used for evaluation of graded levels of maturity in cost estimating as an element of a sustainable decommissioning policy framework.

	Maturity Level / Element	Level 1 Ad hoc	Level 2 Incipient	Level 3 Developing	Level 4 Advanced	Level 5 Leading
2	**Cost estimating for decommissioning liabilities:** Attributes that describe different maturity levels in cost estimating for decommissioning liabilities in a sustainable decommissioning framework	Cost estimates do not exist (for this case study by free public access to the website).	Cost estimate for decommissioning liabilities is known to exist but must be requested from the regulatory agency. There is no free public access to it.	Cost estimate for decommissioning liabilities is publicly accessible for free but not regularly updated (at least every three) for either individual asset or aggregate level.	Cost estimate for decommissioning liabilities is (i) publicly accessible for free, (ii) regularly updated (at least every three years), and (iii) the cost estimate exists at aggregate level.	Cost estimate for decommissioning liabilities is (i) publicly accessible for free, (ii) regularly updated (at least every three years), and (iii) exists at individual asset or field or well level.

Table 11: Attributes used for evaluation of graded levels of maturity in production decline/reserve forecast as an element of a sustainable decommissioning policy framework

	Maturity Level / Element	Level 1 Ad hoc	Level 2 Incipient	Level 3 Developing	Level 4 Advanced	Level 5 Leading
3	**Production decline forecast and remaining reserve:** Attributes that describe maturity levels in management of production decline and remaining reserve forecast data in a sustainable decommissioning framework	Consistent production rates - historical and future, and remaining reserves data do not exist (for this case study, via a free public access to the website).	(i) Production forecast rates and remaining reserve data, are known to exist within the regulatory agency but not publicly accessible for free or (ii) consistent historical production data that is adequate to make production forecast, is publicly accessible for free.	There are production forecast rates and remaining reserve data presented at either individual field level or a higher aggregate level and are publicly accessible for free but not regularly updated (not updated for over a year).	There are consistent production forecast rates and remaining reserve data (i) presented at a higher aggregate level, (ii) publicly accessible for free, and (iii) regularly updated (at least annually).	There are consistent production forecast rates and remaining reserves data (i) presented at individual field and/or well level, (ii) publicly accessible, and (iii) regularly updated (at least annually).

Table 12: Attributes used for evaluation of graded levels of maturity in vulnerability to decommissioning default risk as an element of a sustainable decommissioning policy framework

	Maturity Level / Element	**Level 1 Ad hoc**	**Level 2 Incipient**	**Level 3 Developing**	**Level 4 Advanced**	**Level 5 Leading**
4	**Vulnerability to decommissioning default risk & volume of scope of work management:** Attributes that describe maturity levels in management of vulnerability to decommissioning default risk and volume of scope of decommissioning liabilities in a sustainable decommissioning framework	There is no incremental completion of some of the decommissioning scope of work and no objective to maintain a ratio of not less than one, between the asset's remaining value and cost of decommissioning liabilities	There is incremental completion of some of the decommissioning scope of work and an objective to maintain a ratio of not less than one, between the asset's remaining value and cost of decommissioning liabilities, but coverage ratio result is not accessible to the public for free.	There is incremental completion of some of the decommissioning scope of work and an objective to maintain a ratio of not less than one, between the asset's remaining value and cost of decommissioning liabilities. The coverage ratio result is accessible to the public for free, even though it is not regularly updated.	There is (i) incremental completion of some of the decommissioning scope of work, (ii) an objective to maintain a coverage ratio of not less than one, between the asset's remaining value and cost of decommissioning liabilities at an aggregate regional or entity level, and (iii) a regularly updated (minimum of quarterly) coverage ratio result that is publicly accessible for free.	There is (i) incremental completion of some of the decommissioning scope of work, (ii) an objective to maintain a coverage ratio of not less than one, between the asset's remaining value and cost of decommissioning liabilities at the individual field level, and (iii) a regularly updated (minimum of quarterly) coverage ratio result for each individual field that is publicly accessible for free.

Table 13: Attributes used for evaluation of graded levels of maturity in management of post-decommissioning activities as an element of a sustainable decommissioning policy framework

	Maturity Level / **Element**	**Level 1 Ad hoc**	**Level 2 Incipient**	**Level 3 Developing**	**Level 4 Advanced**	**Level 5 Leading**
5	**Post-decommissioning activities management:** Attributes that describe maturity levels in provisions for post-decommissioning phase liabilities in a sustainable decommissioning framework	Provisions for handling post decommissioning liabilities into perpetuity, do not exist or are not explicitly stated, in the regulations.	From the regulations, it is explicitly stated that the government is accountable into perpetuity, for post-decommissioning liabilities from the fields.	The regulations explicitly hold only the last operators of record liable in perpetuity for any post-decommissioning environmental impact of the fields.	The regulations explicitly hold all legacy and last operators severally and collectively liable in perpetuity for any post-decommissioning environmental impact of the fields.	The regulations explicitly hold all legacy and last operators severally and collectively liable in perpetuity for not only post-decommissioning environmental liabilities but also post-decommissioning social, health and economic negative impacts.

Table 14: Attributes used for evaluation of graded levels of maturity in management of financial assurance as an element of a sustainable decommissioning policy framework

	Maturity Level / **Element**	**Level 1 Ad hoc**	**Level 2 Incipient**	**Level 3 Developing**	**Level 4 Advanced**	**Level 5 Leading**
6	**Financial assurance:** Attributes that describe maturity levels in financial assurance mechanism in a sustainable decommissioning framework	There is no information from the regulatory agency's website to show that operators have mandatorily provided required financial assurance for the full value of all their decommissioning liabilities.	There is some information from the regulatory agency's website that operators may have provided financial assurance for some of their decommissioning liabilities but details must be requested from the regulatory agency. There is no free public access to the information.	Operators have provided financial assurance instruments to the tune of the full value of all their decommissioning liabilities, and the information is publicly accessible, but not regularly updated (takes more than a quarter before it is updated).	Operators have provided financial assurance instruments to the tune of the full value of all their decommissioning liabilities, and the information is presented at a higher aggregate level (e.g. group of wells or fields), publicly accessible for free and updated at a minimum, quarterly.	Operators have provided financial assurance instruments to the tune of the full value of all their decommissioning liabilities, and information is presented at individual field level, publicly accessible for free, and updated at a minimum, quarterly.

Table 15: Attributes used for evaluation of graded levels of maturity in stakeholder engagement as an element of a sustainable decommissioning policy framework

	Maturity Level / Element	Level 1 Ad hoc	Level 2 Incipient	Level 3 Developing	Level 4 Advanced	Level 5 Leading
7	**Stakeholder engagement:** Attributes describing maturity levels in provisions for stakeholder engagement in a sustainable decommissioning framework	There is no requirement for environmental impact assessment (EIA) or stakeholder engagement before approval of decommissioning plan or activity. Or the websites do not make any mention of stakeholder engagement process or requirement for decommissioning as part of the agency's responsibilities.	There is no EIA or stakeholder engagement process/roadmap particularly defined for decommissioning phase but decommissioning projects can ride on the general EIA/stakeholder engagement requirement meant for projects at other phases of petroleum field	(I) There is an EIA or stakeholder engagement process particularly defined for decommissioning phase and it is accessible to the public from the agency's website. (II) It provides less than 30 days for public comments and notwithstanding the comments, the government's political appointee with advice from the regulatory agency has the final decision on the decommissioning plan.	Similar to level 3 except that the process provides 30 days or more for public comments but notwithstanding the comments, the government's executive minister or political appointee with the advice of the regulatory agency has the final decision on the decommissioning plan.	Similar to level 4 except that the publicly accessible regulation or information on the agency's website, informs stakeholders that their comments must be either satisfactorily addressed, or withdrawn, or settled in court, before a final decision is made on the decommissioning plan.

Table 16: Attributes used for evaluation of graded levels of maturity in stakeholder engagement as an element of a sustainable decommissioning policy framework

	Maturity Level / Element	**Level 1 Ad hoc**	**Level 2 Incipient**	**Level 3 Developing**	**Level 4 Advanced**	**Level 5 Leading**
8	**Regulatory capacity:** Attributes describing maturity level of regulatory capacity in a sustainable decommissioning framework	(I)The government executive ministry for growth of the natural resource industry also directly regulates the decommissioning process. (II)There are some few guidelines for decommissioning in the regulation and/or provisions for decommissioning in the separate agreements for each field.	(I)There are multiple regulatory agencies severally and collectively responsible for different parts of the decommissioning process. It is not clear which agency takes the lead, and there is some ambiguity about the process. (II) Decommissioning plans already approved or undergoing review, are not publicly accessible for free from the agencies websites. (An indication that regulator has a large slack and not closely monitored by the public)	(I) Only one or two agencies are responsible for (or lead) decommissioning and are separated from the government executive ministry responsible for the growth of the industry. (II) Decommissioning plans already approved or undergoing review, are publicly accessible for free from the agencies websites but not regularly updated (updates take longer than a quarter to be done).	(I) Only one or two agencies are responsible for (or lead) decommissioning and are separated from the government executive ministry responsible for the growth of the industry. (II) There is summary information (name of assets, location, etc.) on decommissioning plans already approved or undergoing review, publicly accessible for free from the agencies websites. The information is updated at a minimum, quarterly.	I) Only one or two agencies are responsible for decommissioning and are separated from the government executive ministry responsible for the growth of the industry. (II) Decommissioning plans submitted for review by operators, are publicly accessible for free on agencies websites. (Indication that agency is active and closely monitored by the public, which reduces slack). (III) Information is updated at a minimum, quarterly.

8.7. Data Gathering

Historical data on reserves and crude oil production from BP's statistical review (British Petroleum, 2016) will be the primary sources of data for production decline and fiscal policy analysis. The data includes information from 1958, when oil was first discovered in commercial quantities in Nigeria, to 2015. Where there is significant gap in data series, other data sources that are appropriately cited will be consulted to close the gaps. These data sets are available in the public domain.

Cost estimate data were gathered from publicly declared annual financial reports of some oil companies operating in Nigeria (Appendices A & B). These reports spanning several years were either declared in the company's websites or with the Securities and Exchange Commission in the United Sates or its sister agency, the Canadian Securities Administration in its public accessible database, System for Electric Document Analysis and Retrieval (SEDAR).

Data for the development of Fairbanks maturity model for sustainable decommissioning of petroleum fields and the application of the model to Nigerian onshore fields were gathered from the websites of regulatory agencies or entities for decommissioning related activities in Nigeria, and some evidently leading regions with experience in decommissioning of petroleum fields. These pieces of information on policy elements, empirical status, and performance were used as input data for comparative analysis. Unger et al. (2015) adopted a web-based and self-participatory survey questionnaire data gathering approach to collect input data used to evaluate the level of jurisdictional maturity model for risk management, accountability, and continual improvement of abandoned solid mineral remediation programs in Australia. This study did not adopt the self-participatory survey questionnaire data gathering approach as it seeks to be biased toward information in public space that will not be challenging for public stakeholders to access. This result will incentivize their participation in the policy development and implementation process. Lawal (2008) and Stakeholder Democracy Network (2015) have already observed a low level of concern and consideration for decommissioning by the Nigerian government. Therefore, it could be tenable to assume that a self-participatory survey may not reveal a different level of maturity from what will be gathered from web-based sources. Moreover, using privileged input data from self-participatory assessment by regulatory agencies will not use results from the publicly accessible domain. It will not align with this study's objective and proposition that public stakeholders should have access to sufficient and adequate information that can support and incentivize their effective participation in public policy decision making for the decommissioning phase of the petroleum fields. Overall, where there are significant data gaps, other secondary data sources, appropriately cited, were consulted.

8.8. Data Analysis

Data analysis to test the results and answer the research questions will be mainly through scenario planning description and analysis, sensitivity analysis, comparative analysis, and abstraction.

Sensitivity analysis is a common data analysis approach that tests the gathered data for emphasized behavioral effect from some particular parameter, while abstraction involves translation of empirical observations from the results into concepts and is useful in exploratory studies (Routio, 2007a).

A comparative analysis of decommissioning practices at the elemental level between regions with experiences in decommissioning was undertaken to set the different levels of maturity and identify their attributes. Some of the higher maturity level requirements and attributes can be viewed as coming from a normative approach – "what is should be" versus a descriptive approach – "what it is." However, normative research approaches have been widely used for researches in decision sciences and policy studies to help with the understanding of biases and avoiding the errors of omission and commission in decision making (Baron, 2004; Routio, 2007a). Normative theories and approaches consider "how people should behave when confronting a risky decision" (Damnjanović & Janković, 2014; Suhonen, 2007) or how things should be in contrast to a descriptive approach, which considers how things are. Despite arguing that normative approaches are limiting as they assume close boundaries and scope, Singh (2016) acknowledged that one typical approach to setting guidelines and defining the level of maturity is the normative approach. It helps to set and understand the differences in maturity levels and can be used as a basis for a continuous improvement road map.

The results from these methodologies and models using Nigerian onshore crude oil fields as a case study are presented in the next chapter, chapter 9. These methodologies and models which are developed and presented in this study as an extension to the frontier of knowledge in decommissioning, can be adapted and applied to any other petroleum producing region in the world.

9. Results and Results Analysis

Using Nigerian onshore crude oil fields as a case study, the models presented in chapter 8 were demonstrated to answer the research questions.

9.1. Results from Nigeria_Onshore_Production_Decline_Model: Remaining Production Profile Forecast for Nigerian Onshore Crude Oil Fields

For deterministic analysis, aggregate production forecast results (Figure 49) based on exponential and harmonic decline curve methods were determined for onshore fields in Nigeria.

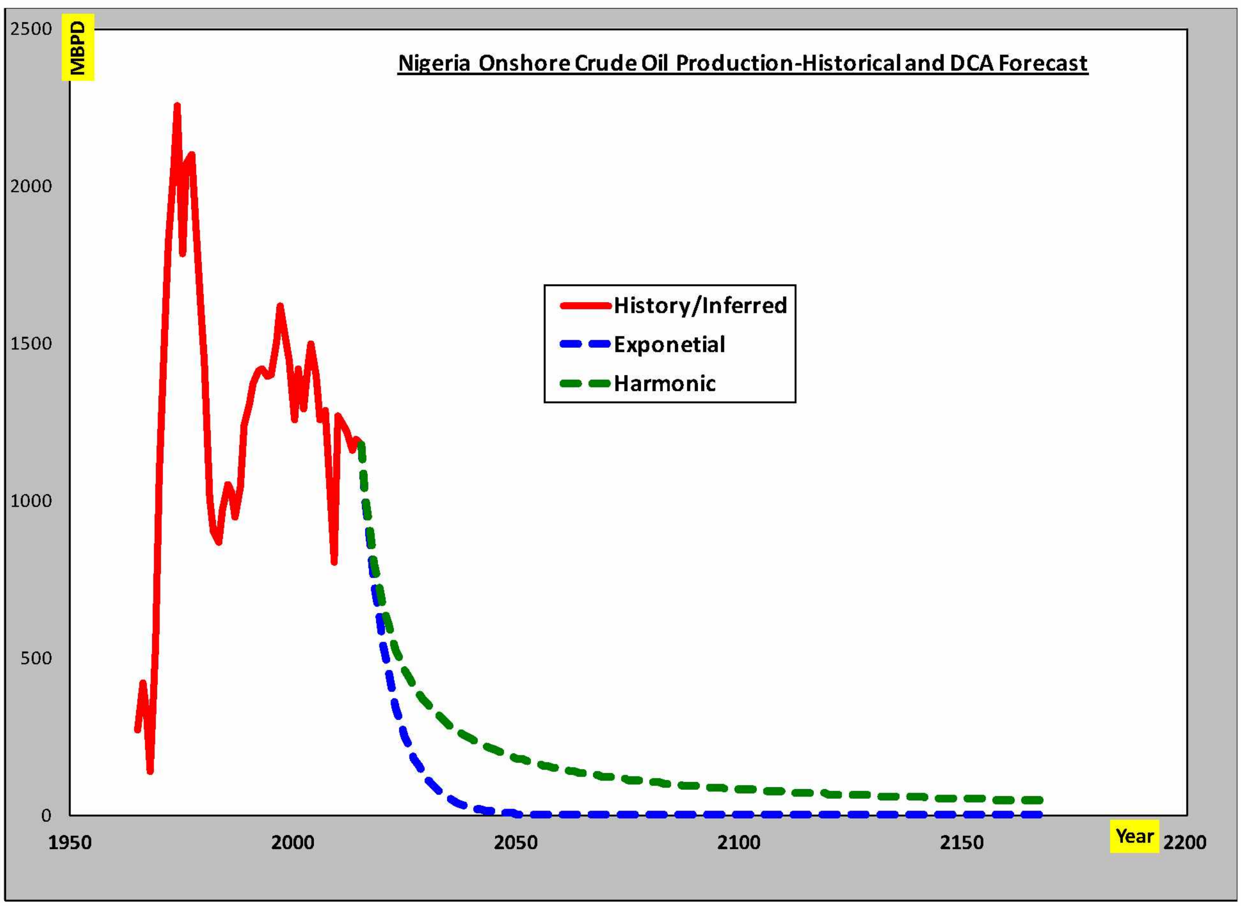


Figure 49: Crude oil production profile forecast for Nigeria onshore fields

The hyperbolic decline curve method with a stochastic variation of the hyperbolic exponent "b" over a range of value between 0 and 1, was adopted to determine the probabilistic results. The probabilistic results were used to determine the remaining rent in chapter 9.3.

9.1.1. Discussion of Results from Nigeria_Onshore: Production_Decline – Remaining Production Forecast

The production forecast results show that crude oil production from Nigeria's onshore fields will be collectively less than 100 Mbopd within the next 40 – 50 years or approximately 2070. For about 100 flowstations, this will translate to approximately 1 Mbopd per flowstation. This production rate will be below a sustainable economic production threshold for most oil MOCs and even some indigenous oil companies. Under this circumstance, most MOCs would have exited the fields and very small oil companies or "mom and pop" types of indigenous oil companies will be the predominant group operating in the region. These very small indigenous companies may most likely be less robust, financially. They will be focused on how to collect as much revenue as possible and as quickly as possible, from the fields. They may not care as much about health, safety and environment objectives, and could abandon the fields for the public to properly decommission. Moreover, 50 years is a relatively inadequate time for any common resource-related policy direction change and successful implementation in Nigeria. Without an urgent proactive plan for decommissioning, this bleak forecast for decommissioning can become a reality for the onshore crude oil fields in Nigeria, particularly if the cost of decommissioning liabilities becomes very high, relative to the revenue available for decommissioning.

9.2. Results from Nigeria_ARO_Cost_Model: Cost of Decommissioning Liabilities for Nigerian Onshore Crude Oil Fields

Nigeria_ARO_Cost_Model determines the cost estimate for decommissioning liabilities from onshore crude oil fields in Nigeria based on the methodology presented in chapter 8 that takes publicly declared ARO data as input data (Appendices A & B). The overview of the model with its input data (unshaded cells) and results (shaded cells) is shown in Figure 50. The deterministic aggregate cost of decommissioning liabilities from onshore crude oil fields in Nigeria was determined to be about $3 billion.

Reporting Company	Heritage	Heritage	SEPLAT	SEPLAT	SEPLAT	SEPLAT	SEPLAT	ELAND	ELAND	ELAND	ELAND
OML (Oil Mining Lease)	OML-19	OML-19	OMLs-4/38/41	OMLs-4/38/41	OMLs-4/38/41	OMLs-4/38/41	OMLs-4/38/41	OMLs-40/49	OMLs-40/4	OMLs-40/4	OMLs-40/4
Government Joint Venture Interest (JV_{govt})	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%
Working interest of Reporting Company (WI_{report})	97.50%	97.50%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Number of Flow stations in Report Scope (FS)	9	9	5	5	5	5	5	1	1	1	1
Declared ARO cost US$ MM (C_{WI})	22.75	21.00	10.11	15.73	14.58	9.84	2.97	17.74	11.98	12.31	9.91
Reported Cost Year (Y_{report})	2012	2013	2011	2012	2013	2014	2015	2012	2013	2014	2015
Reported EOFL Year (Y_{EOFL})	2035	2035	2025	2025	2027	2036	2052	2019	2026	2026	2026
Reported Discount Rate (r)	10%	10%	15%	15%	12%	15%	11%	5%	3%	3%	3%
Reported Inflation Rate ("i")	2%	2%	2%	2%	2%	2%	2%	2%	2%	4%	2%
Reference or Cost study Year (Y_{ref})	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
Effective ARO Working Interest (WI_{ARO})	**43.9%**	**43.9%**	**45.0%**	**45.0%**	**45.0%**	**45.0%**	**45.0%**	**45.0%**	**45.0%**	**45.0%**	**45.0%**
Future value of WI Decommissioning cost US$ MM at EOFL (C_{EOFL})	**203.7**	**170.9**	**71.5**	**96.8**	**71.2**	**212.9**	**141.2**	**25.0**	**17.6**	**17.5**	**13.7**
WI Decommissioning cost US$ MM at reported year (C_{report})	**129.2**	**110.6**	**54.2**	**74.8**	**54.0**	**137.7**	**67.9**	**21.7**	**13.6**	**11.0**	**11.0**
UCCI Escalation Index (U_{index})	**0.7**	**0.7**	**0.8**	**0.7**	**0.7**	**0.7**	**0.9**	**0.7**	**0.7**	**0.7**	**0.9**
WI Decommissioning cost US$ MM at reference year (C_{ref})	**90.4**	**77.4**	**43.4**	**52.4**	**37.8**	**96.4**	**61.1**	**15.2**	**9.5**	**7.7**	**9.9**
100% JV Decommissioning cost US$ MM for each operator ($_{100\%\ JV}$)	**206.09**	**176.40**	**96.40**	**116.36**	**83.99**	**214.26**	**135.73**	**33.79**	**21.15**	**17.05**	**22.06**
Decommissioning cost US$ MM per facility for each operator ($C_{operator}$)	**23**	**20**	**19**	**23**	**17**	**43**	**27**	**34**	**21**	**17**	**22**
Average Decommissioning cost US$ MM per facility round up to next US$MM 10, "$C_{average}$"			**30**	Number of FS in Onshore Nigeria	100	**Overall Aggregate Decommissioning Cost for all 100 Onshore Fields in Nigeria (Reference Year US $BLN) "C"**					**3.0**

Figure 50: Model overview and results of cost estimate for decommissioning of onshore crude oil fields in Nigeria

9.2.1. Discussion of Results: Nigeria_ARO_Cost_Model

Cost estimates for decommissioning of onshore fields in Nigeria, as calculated in this study, vary based on the operator. The average decommissioning cost per facility is $30 million. Operators with low estimates and smaller facilities suggest US$17 million per facility, while the operators with higher estimate suggest cost estimate of US$43 million for a facility, as shown in Figure 50. Rounded up to the nearest $10 million, it is a range of $20 million to $50 million decommissioning cost per facility. The reported ARO liabilities are represented in PV terms based on discount rates, inflation rates, and other cost factors that vary with operators. Even with the financial accounting standards, there are differences in ARO estimates arising from different management discretions applied by each operator. Pittard (1997) made similar observations in a global study of decommissioning cost estimates for offshore fields. A sensitivity analysis in section 9.2.2 to determine the influence of these parameters on the cost estimate will help to qualify the use of these cost estimates in decision making.

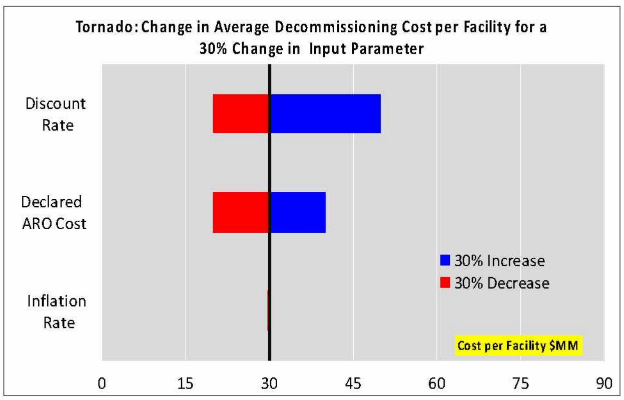
From the results presented in Figure 50, the deterministic aggregate and ROM decommissioning cost estimate for all onshore fields in Nigeria is within the range of US$2 billion to US$5 billion and an average of $3 billion. The maturity level of project scope definition used for this cost estimate falls within 0% to 2% completion, which according to the Association for the Advancement of Cost Engineering (AACE) International (2016), puts the cost estimate in a class 5 estimate with a −50% to +100% accuracy. The AACE categorized cost estimates into five classes, class 1 to class 5. Class 1, with the highest accuracy range, is recommended for a project with 100% completion and high maturity level of scope definition, while class 5, with the least accuracy range, is recommended for projects with low (0–2%)

completion and maturity level of scope, such as decommissioning of onshore crude oil fields in Nigeria. The scope, size, and cost may vary across approximately 100 facilities. The spread notwithstanding, it is expected that with averaging of costs for different sizes of facilities and based on the decommissioning cost estimate data points used in this study, the estimated range is a reliable ROM cost estimate. It can be used to facilitate discussions on decommissioning of onshore fields in Nigeria, particularly given that there is no generic cost estimate to begin with. Note that this study has assumed the gathering facility as a unit parameter for decommissioning scope of work, which covers the entire field infrastructure that is associated with a given gathering facility. Kaiser (2015b) obtained a similar average cost for the GOM using adjusted reported settled ARO liabilities.

The EOFL years reported also vary across fields and operators, which is expected. However, the reported EOFLs fall within 2026 to 2052. None of these are in the next century or even half a century from 2016. We can infer that thoughts, discussions, and hence planning for the EOFL scenarios for onshore fields in Nigeria is no longer a premature effort. Even the operators that acquire these fields from MOCs are not looking at a very far future EOFL. The future is no longer too distant to generate decommissioning cost estimates that will facilitate public engagements, policy discussions, and proactive planning efforts for decommissioning of these fields. As noted earlier, decommissioning and restoration project for Ogoni field in Nigeria that is driven by sociopolitical crises and pressure from the United Nations, has been in the discussion for a decade, and is estimated to be a 25-year lifecycle project (Osibanjo 2017). From antecedents, it could take 3 to 4 decades to achieve stakeholder engagement, draft and secure approval of a focused policy framework, develop financial assurance strategies, secure funds, and proactively get ready for the decommissioning of onshore fields in Nigeria. A proactive plan that involves the public is required for sustainable decommissioning. Public awareness of the potential cost of decommissioning and associated environmental liabilities will be a credible catalyst for this process to commence. Within the limits of judgments and assumptions made, the simple and relatively reliable cost estimate approach presented in this study will help facilitate the roadmap toward sustainable decommissioning of the onshore fields in Nigeria.

9.2.2. Sensitivity Analysis

McEown (2017) concluded that the calculation of ARO costs is fraught with "a significant number of judgments," some of which were highlighted in Figure 29. This is expected of the methodology in Figures 40 and 41, being almost a reverse of the method in Figure 29. A sensitivity analysis will help to put into perspective some of the assumptions made, in order to fill information gaps in input parameters when calculating the cost of decommissioning from declared ARO cost. This analysis will identify the parameters that have more significant impact on the estimated cost of decommissioning. In this study, inflation rates were not declared by all the operators, except for one operator, Eland Oil & Gas PLC, which declared 2% and 4.75% in separate instances (Appendices A & B). An inflation rate of 2% was assumed for all the other operators, based on Eland's report (Eland Oil & Gas PLC, 2013; 2016). Inflation and discount rates can be susceptible to management bias (Seplat Petroleum Development Company, 2014) and as shown in Appendix A. The declared PV of ARO cost in financial reports may also be affected by enterprise factors. A sensitivity analysis based on two scenarios of a 30% and 50% change in values of declared ARO cost, inflation rate, and discount rate showed that the calculated cost of decommissioning is more sensitive to discount rate than inflation rate, as shown in the tornado diagrams in Figure 51. From the tornado diagrams, discount rates and declared cost of ARO are more significant input data than inflation rate. This sensitivity result should be recognized when using decommissioning cost estimates derived from a company's annual financial reports for any decision.



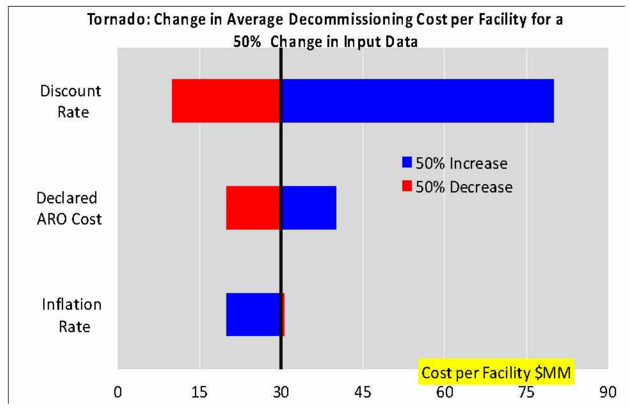


Figure 51: Tornado diagrams for average decommissioning cost for Nigerian onshore fields

A probabilistic Monte Carlo sensitivity analysis was also undertaken to determine the confidence interval for the range of cost estimates presented in this study. In the absence of a large data set and information, the variables were assumed to be random with uniform distributions between the maximum and minimum values identified from the annual reports (Altiok & Melamed, 2007; Vialar, 2015). For inflation rate i, the minimum value was 2% and maximum 4.75%. For discount rate r, the minimum was 3% and maximum was 15%. For declared ARO cost C_{WI}, the minimum and maximum multiple of 1 and 3 respectively, were assumed. Kaiser & Liu (2015) had earlier used a two to three times multiple variation for a tableau of decommissioning cost estimates for deepwater floating structure in GOM.

The distribution result in Figure 52 is skewed partly owing to the limitations of a small data set. Recognizing this limitation and skewed distribution, the median cost estimate is the P50 decommissioning cost per facility, which is $30 million. The decommissioning cost per facility range has a lower limit of $20 million which corresponds to the P25 cost estimate and the upper limit of $50 million which corresponds to the P75 cost estimate. This represents a 50% confidence interval for the decommissioning cost estimate per facility range of $20 million to $50 million. In using the cost range, this sensitivity results should be recognized.

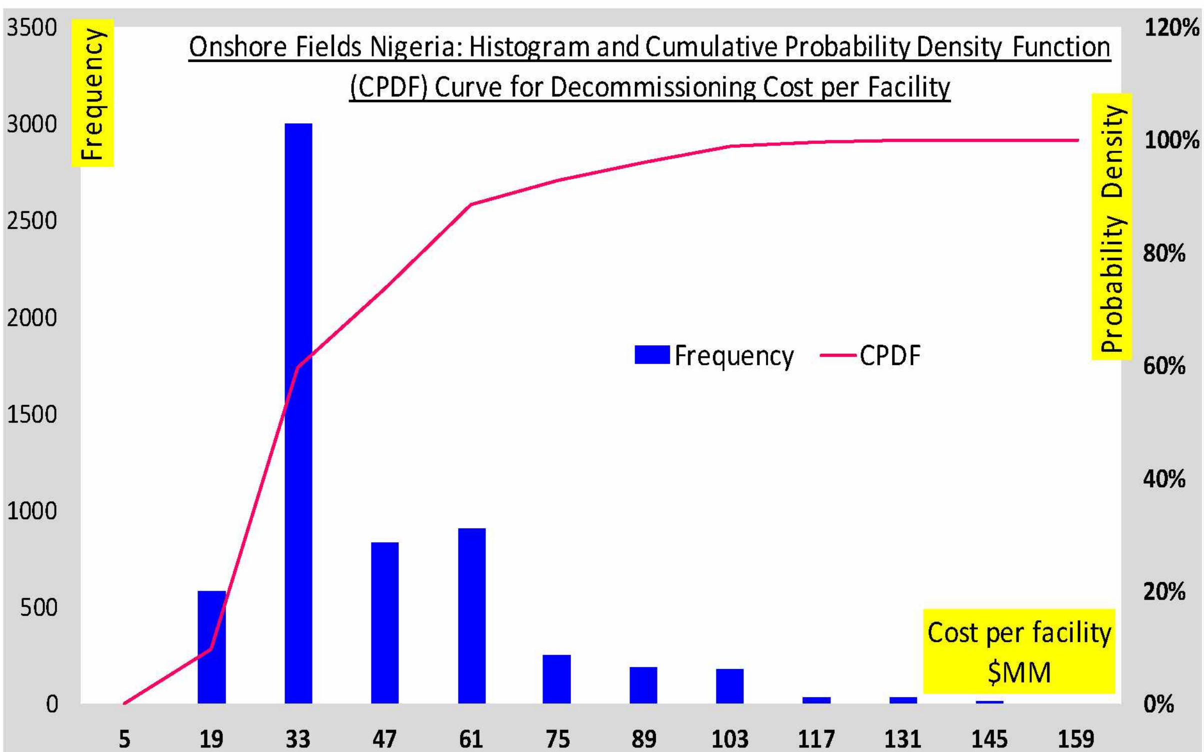


Figure 52: Probabilistic Monte Carlo evaluation for decommissioning cost per facility

9.2.3. Conclusions and Recommendations from "Nigeria_ARO_Cost_Model"

First, this methodology and associated model succeeded in estimating a generic aggregate cost for meeting asset retirement and decommissioning obligations for onshore fields in Nigeria, which, from the literature search, could be the first for Nigeria. This will serve as an initial reference point for public discussions on cost of decommissioning liabilities for oil and gas facilities in Nigeria.

Second, it has demonstrated a method of estimating the cost of asset retirement and decommissioning obligations that is amenable to publicly accessible cost data in published financial reports. This method does not require gaining use permission from operating companies, and leverages the reliability and reputation of auditing firms for data transparency and consistency. This will put operating companies on the defense, rather than the "tutor" position, when having conversations with the general public and government agencies on decommissioning. It will facilitate constructive and authentic discussions, assessment, and evaluation of decommissioning liabilities, particularly during asset divestment.

Third, while the opportunity presented in financial reports of new companies that operate in only onshore fields is acknowledged, this is an extension to the frontier of knowledge in decommissioning and abandonment of onshore field assets in Nigeria. It is recommended that public stakeholders use the method demonstrated in this study to overcome the barriers of proprietary cost data and independently determine costs of decommissioning liabilities for crude oil facilities. This will attract minimal transaction cost. Regular monitoring of financial reports from operating companies to revise cost estimates for decommissioning liabilities is also suggested. Government agencies, even with inadequate capabilities as observed in developing nations, can apply these steps under an asset divestment scenario to determine and independently set a zone of possible agreement, price for reclamation bonds, and reasonable bounds for decommissioning obligations that could potentially fall on the public.

Fourth, the cost of decommissioning and associated environmental liabilities for the onshore fields in Nigeria, as determined from this study, is going to be fairly substantial. As a simple illustrative analogy for communication purposes, at a net profit margin of US$10/bbl, it will require setting aside 1% of profit from a total of 2,500 Mbopd for 33 years to cover a US$3 billion decommissioning cost and 55 years for a US$5 billion cost. Based on the EOFL declared in the financial reports, none of the current operators envisage operating the onshore fields beyond 40 years from 2016. The Nigerian government may need to start the implementation of some form of financial assurance scheme similar to those implemented in the GOM, Canada, and the UK, to protect the government from exposure to the huge decommissioning risk. Nigeria may need a specific ARO regulatory requirement that demands cost estimates and preliminary plans for decommissioning of facilities from the operators on a regular basis. The plan should include a preliminary environmental impact assessment on the future decommissioning project, which will mandate public participation in the decommissioning plan and eventually the development of decommissioning policy. Financial standards and reporting bodies in Nigeria should explore ways to provide companies adequate disclosure and data on ARO in their financial reports.

Future studies will require detailed cost estimating exercises to calculate the respective cost for sub-elements of the decommissioning scope of work, such as flowlines, pipelines, wells of different categories of depth, and other infrastructure in Nigeria.

9.2.4. Limitations: Nigeria_ARO_Cost_Model

The data set used in this study to estimate the aggregate cost of decommissioning for onshore fields in Nigeria is small, even though deemed representative enough for an initial generic and aggregate ROM cost of decommissioning. The scope has been aggregated for all facilities with the assumption that averaging over a larger number of facilities will address the challenges posed by differences in size and scope of individual facilities. Therefore, the results cannot be used for investment decisions or commercial evaluation on a field-by-field basis.

9.3. Results from EOFL Scenario Planning for Nigerian Onshore Crude Oil Fields

There could be two broad planning approaches—proactive response and reactive response planning approaches—to decommissioning. Leveraging an end of life theme, there could be two extreme boundaries of plausible government's proactive response to decommissioning in Nigeria. Either the government consciously sets a time for a decommissioning plan to proactively commence, which is described as the **euthanasia scenario,** or wait until the fields decline to a clear uneconomic condition at which time decommissioning plan will commence, described as the **graceful death scenario**. On the reactive planning side, the government has no plans for decommissioning until the operators abruptly exit the fields and the government is suddenly compelled to take over the fields and associated decommissioning liabilities. The operators are ahead of the government in awareness about the uneconomic situation of the fields. This scenario is described as the **sudden death scenario**. These three EOFLs or decommissioning phase scenarios will help in the analysis to support robust decision making on decommissioning related issues for Nigerian onshore crude oil fields.

Proactive Response Approaches and Scenarios: For a proactive response approach, leveraging an end of life theme, two major future scenarios — euthanasia and graceful death scenarios — of government response approaches to decommissioning of onshore fields in Nigeria were created to support this study. These will typify a deliberate approach from the government toward decommissioning. There could be other variant scenarios, but considering the extreme bounds of government's plausible proactive response strategy, euthanasia and graceful death scenarios will represent the credible major boundary scenarios.

9.3.1. Euthanasia Scenario

Under this scenario, a government recognizes the inevitability of the fields becoming uneconomical at some time in the future and for reference purposes proactively sets a time for a decommissioning to commence. The time may not be exact, but a probable time for proactive planning purposes to address the problem of decommissioning the onshore crude oil fields. This study assumed 50 years from 2020, which is 2070. 2020 is a landmark milestone year for developmental projects in Nigeria. Moreover in 50 years from 2020, the fields would have collectively operated for approximately 120 years, which should be a reasonable economic life span. The intent is that the imminence of the problem, if there is, will be seen from the model to support a case for immediate development of a strategy and plan for decommissioning.

Moreover, from the pessimistic exponential and optimistic harmonic decline curve analysis, crude oil production from all onshore fields will be approximately 100 Mbopd and 50 Mbopd respectively, by 2070. This will translate to an average of 1 Mbopd or 0.5 Mbopd per facility, which will not be an economic operational output for a facility (Figure 49). Therefore, 2070 is a credible conservative economic EOFL assumption for a deliberate commencement of plans for decommissioning.

The behaviors of the remaining revenue accruing to the government from royalties, JV profit, and tax revenue stream, and their comparison with the cost of decommissioning liabilities will provide inference on the imminence and vulnerability to decommissioning default risk.

9.3.2. Graceful Death Scenario

Under this scenario, the fields are allowed to operate until they generate net loss from operations before they are abandoned. The government is more focused on getting every drop of revenue from the fields, hence decommissioning plan and policy development could be delayed much further. Modeling this scenario involves using price, operational efficiency, and production cost to evaluate for the first year in the sequence that will yield a net negative revenue stream. Similar to the euthanasia scenario, the behaviors of the remaining revenue accruing to the government from royalties, JV profit, and tax revenue streams and their comparison with the cost of decommissioning liabilities will provide inference on the imminence and vulnerability to decommissioning default risk under this scenario.

9.3.3. Reactive Response Approach: Sudden Death Scenario

A third future scenario—sudden death scenario contrasts the deliberate approaches. The sudden death scenario typifies an abrupt exit from the fields by operators, a scenario that is characterized by lack of any form of preparedness for decommissioning before the sudden EOFL event. It is analogous to dying intestate and the government taking over the fields–operations and decommissioning activities inclusive. It may be due to bankruptcy, sociopolitical reasons, or economic and other business reasons. If an operator suddenly exits a field, government will take over the operatorship of the field and execute decommissioning at the EOFL. In this situation, discrimination between tax, royalties, and JV profit share revenue streams will no longer matter. The government takes over operations and no longer collects taxes or royalties, but all net operating revenues. The government will use the revenue to manage the operational activities for any marginal economic life remaining in the field, and eventually pays for the proper decommissioning of the fields. The net operating revenue becomes the fiscal element and policy objective of interest as there will no longer be a functional discrimination between revenue streams. The gross revenue less operating expenditure will go to the government under the sudden death scenario as it must cover decommissioning cost with these funds. The funds have to be adequate to cover the cost of decommissioning else the government will have to source funds from some other sources to cover the cost of proper decommissioning of the fields. The objective will be to determine the range of duration before the occurrence of this scenario that will leave the government in a situation where the fields can no longer pay for their decommissioning liabilities and the government will have to source funds from tax paying public to complete decommissioning of the fields.

9.4. Vulnerability to Decommissioning Default Risk: DCRV_Nigerian_Onshore Model Results

Based on the methodology for determination of DCRV and DCR discussed in chapter 8, a model DCRV_Nigerian_Onshore_Model was developed to calculate the DCR and DCRV for each DCA production forecast and associated revenue stream. Based on the production forecast method and associated revenue stream, a tableau of deterministic DCR and DCRV results was generated as shown in Figures 53 – 76 for all euthanasia, graceful, and sudden death scenarios. The DCRV results were determined with reference to the year for this study, which was 2016. The results are presented for each revenue stream under each scenario as follows; euthanasia and graceful death scenarios – chapter 9.4.6.1 (royalty revenue stream), chapter 9.4.6.2 (JV profit share revenue stream), chapter 9.4.6.3 (tax revenue stream), and sudden death scenario – chapter 9.4.6.4 (net operating revenue stream).

9.4.1. Euthanasia and Graceful Death Scenarios: DCR and DCRV Results for Remaining Royalty Revenue Stream

(a.) Decommissioning Coverage Ratio (DCR): Deterministic Results for Remaining Royalty Revenue from Onshore Crude Oil Fields in Nigeria

Based on the remaining royalty revenue, the expected values of DCR for both scenarios range from 2.1 (exponential DCA) to 2.8 (harmonic DCA) and for the individual deterministic cases, they range from 0.6 to 12.4 (Figures 53 – 55), which indicate high vulnerability to decommissioning default risk. None of the deterministic cases had a DCR greater than 20, which is the threshold for low vulnerability position for Nigerian crude oil fields. Therefore, given the results, vulnerability to decommissioning default risk can be considered high for Nigerian onshore crude oil fields. There is no significant difference between the results from both scenarios, showing that irrespective of the future decommissioning scenario, vulnerability to decommissioning default risk is already high.

Euthanasia Scenario: Remaining Royalty Revenue Decommissioning Coverage Ratio (DCR) and Decommissioning Covergage Ratio vector (DCRV) Aggregrated for Nigerian Onshore Crude Oil Fields

Exponential Decline Curve		Decommmissioning Coverage Ratio *DCR_taxes*											Decommmissioning Coverage Ratio Vector *DCRV_taxes*										
Remaining Tax Revenue ($BLN)	Cost C / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
27.32	$82.60	9.1	4.6	3.0	2.3	1.8	1.5	1.3	1.1	1.0	0.9	2.7	7	4	3	2	1	0	0	0	0	0	1.7
21.96	$66.38	7.3	3.7	2.4	1.8	1.5	1.2	1.0	0.9	0.8	0.7	2.1	6	4	2	1	0	0	0	0	0	0	1.3
14.32	$43.30	4.8	2.4	1.6	1.2	1.0	0.8	0.7	0.6	0.5	0.5	1.4	5	2	0	0	0	0	0	0	0	0	0.7
	Average	7.1	3.5	2.4	1.8	1.4	1.2	1.0	0.9	0.8	0.7	2.1	6.0	3.3	1.7	1.0	0.3	0.0	0.0	0.0	0.0	0.0	1.2

Harmonic Decline Curve		Decommmissioning Coverage Ratio *DCR_taxes*											Decommmissioning Coverage Ratio Vector *DCRV_taxes*										
Remaining Tax Revenue ($BLN)	Cost C / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
37.19	$82.60	12.4	6.2	4.1	3.1	2.5	2.1	1.8	1.5	1.4	1.2	3.6	14	9	6	5	3	2	1	0	0	0	4.0
29.89	$66.38	10.0	5.0	3.3	2.5	2.0	1.7	1.4	1.2	1.1	1.0	2.9	13	8	5	3	2	1	0	0	0	0	3.2
19.49	$43.30	6.5	3.2	2.2	1.6	1.3	1.1	0.9	0.8	0.7	0.6	1.9	10	5	2	1	0	0	0	0	0	0	1.8
Weighted Average		9.6	4.8	3.2	2.4	1.9	1.6	1.4	1.2	1.1	1.0	2.8	12.3	7.3	4.3	3.0	1.7	1.0	0.3	0.0	0.0	0.0	3.0

Figure 53: Euthanasia scenario for Nigerian onshore fields – Deterministic DCR and DCRV with royalty revenue

Graceful Death Scenario: Remaining Royalty Revenue Decommissioning Coverage Ratio (DCR) and Decommissioning Coverage Ratio vector (DCRV) Aggregrated for Nigerian Onshore Crude Oil Fields

Exponential Decline Curve		Decommmissioning Coverage Ratio *DCR_taxes*											Decommmissioning Coverage Ratio Vector *DCRV_taxes*										
Remaining Tax Revenue ($BLN)	Cost C / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
27.32	$82.60	9.1	4.6	3.0	2.3	1.8	1.5	1.3	1.1	1.0	0.9	2.7	7	4	3	2	1	0	0	0	0	0	1.7
21.96	$66.38	7.3	3.7	2.4	1.8	1.5	1.2	1.0	0.9	0.8	0.7	2.1	6	4	2	1	0	0	0	0	0	0	1.3
14.32	$43.30	4.8	2.4	1.6	1.2	1.0	0.8	0.7	0.6	0.5	0.5	1.4	5	2	0	0	0	0	0	0	0	0	0.7
	Average	7.1	3.5	2.4	1.8	1.4	1.2	1.0	0.9	0.8	0.7	2.1	6.0	3.3	1.7	1.0	0.3	0.0	0.0	0.0	0.0	0.0	1.2

Harmonic Decline Curve		Decommmissioning Coverage Ratio *DCR_taxes*											Decommmissioning Coverage Ratio Vector *DCRV_taxes*										
Remaining Tax Revenue ($BLN)	Cost C / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
37.23	$82.60	12.4	6.2	4.1	3.1	2.5	2.1	1.8	1.6	1.4	1.2	3.6	14	9	6	5	3	2	1	0	0	0	4.0
29.92	$66.38	10.0	5.0	3.3	2.5	2.0	1.7	1.4	1.2	1.1	1.0	2.9	13	8	5	3	2	1	0	0	0	0	3.2
19.51	$43.30	6.5	3.3	2.2	1.6	1.3	1.1	0.9	0.8	0.7	0.7	1.9	10	5	2	1	0	0	0	0	0	0	1.8
Weighted Average		9.6	4.8	3.2	2.4	1.9	1.6	1.4	1.2	1.1	1.0	2.8	12.3	7.3	4.3	3.0	1.7	1.0	0.3	0.0	0.0	0.0	3.0

Figure 54: Graceful death scenario for Nigerian onshore fields – Deterministic DCR and DCRV with royalty revenue

Decommissioning cost "C" of $30million per facility for a 100 facilities, aggregrated cost C = $3 BLN

Key for DCR	Key for DCRV
DCR > or = 20 :Low Risk	DCRV > or = 40 :Low Urgency
20 > DCR > 10 :Medium Risk	40 > DCRV > 30 :Medium Urgency
DCR = or < 10 :High Risk	DCRV = or < 30 :High Urgency

Figure 55: Criteria and key to DCR and DCRV metrics

(b.)Decommissioning Coverage Ratio Vector (DCRV) Results: Remaining Royalty

The expected values of DCRV for both scenarios range from 1.2 to 3.0 (Figures 53 – 55) with show an imminence of vulnerability to decommissioning default risk events and high urgency for decommissioning policy development and readiness plan. There is no significant difference between similar cases under both scenarios and none of the individual cases have a DCRV greater than 40, which is the threshold for low urgency situation and a comfortable decommissioning policy development lead time.

The DCRV can also be represented as the intercept between decommissioning cost threshold plot and PV of the remaining royalty revenue plot – a depiction of DCRV which is the number of years between 2016 and time when the PV of the remaining royalty revenue is equal to the decommissioning cost (Figures 56 – 59). Using different cases of cost estimates that could cover the plausible range of cost of decommissioning liabilities for onshore crude oil fields in Nigeria, the charts (figures 56 and 57 for graceful death scenario and figures 58 and 59 for euthanasia scenario) demonstrate that in a no distant future, the remaining revenue from royalties may not be adequate to cover the cost of decommissioning liabilities.

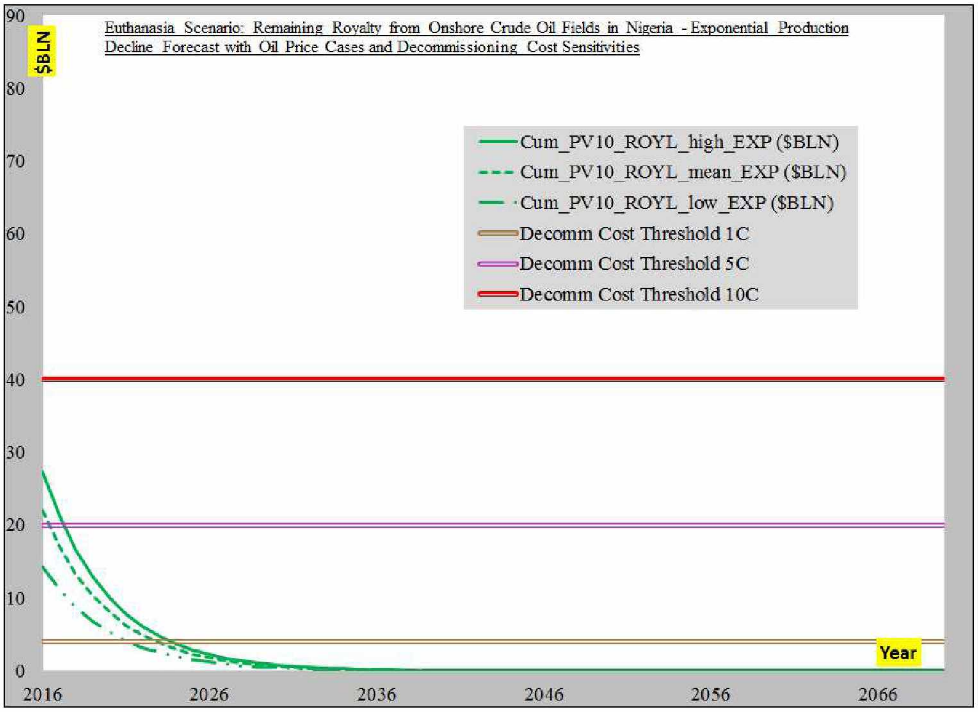


Figure 56: Euthanasia scenario and exponential production decline forecast – Present value of remaining royalty revenue and decommissioning cost thresholds for Nigerian onshore fields

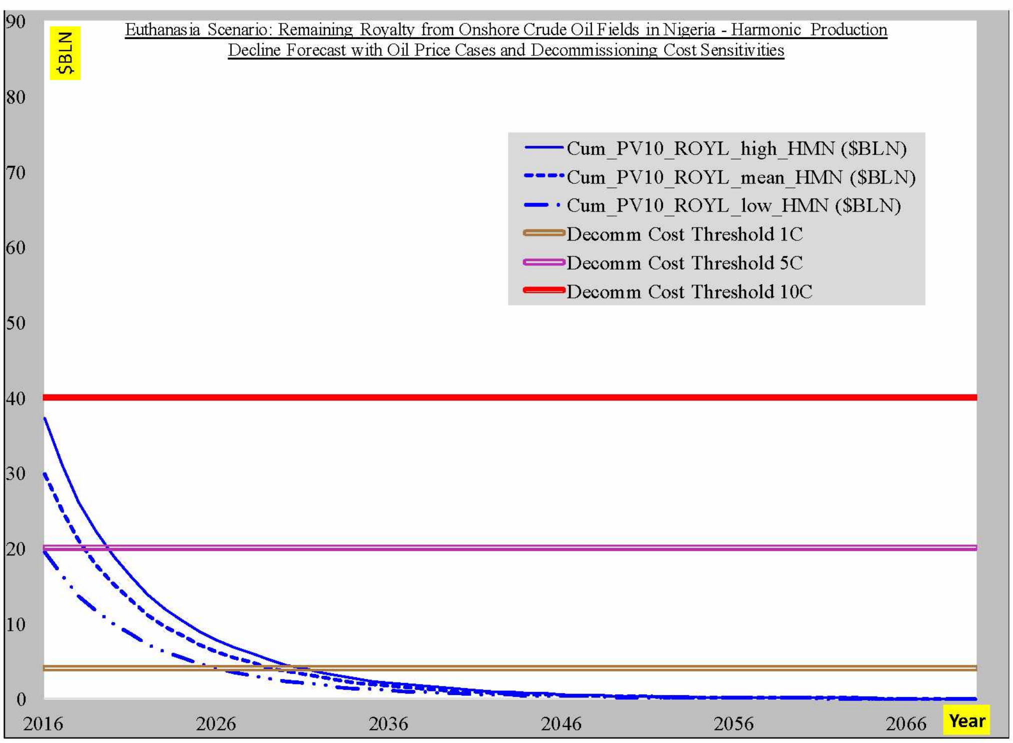


Figure 57: Euthanasia scenario and harmonic production decline forecast – Present value of remaining royalty revenue and decommissioning cost thresholds for Nigerian onshore fields

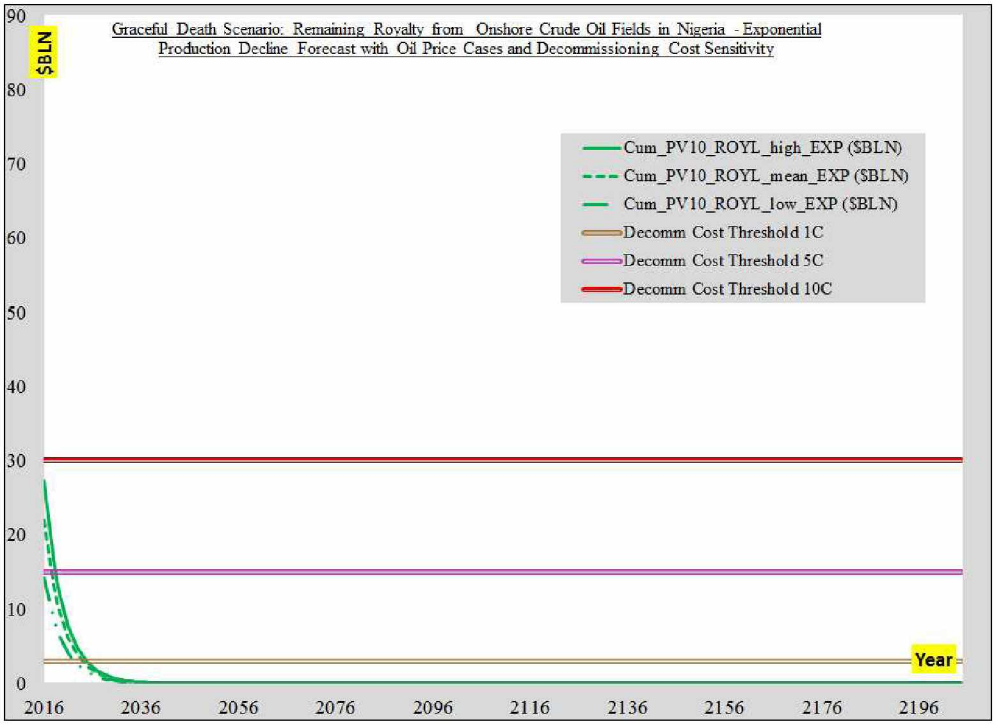


Figure 58: Graceful death scenario and exponential production decline forecast – Present value of remaining royalty revenue and decommissioning cost thresholds for Nigerian onshore fields

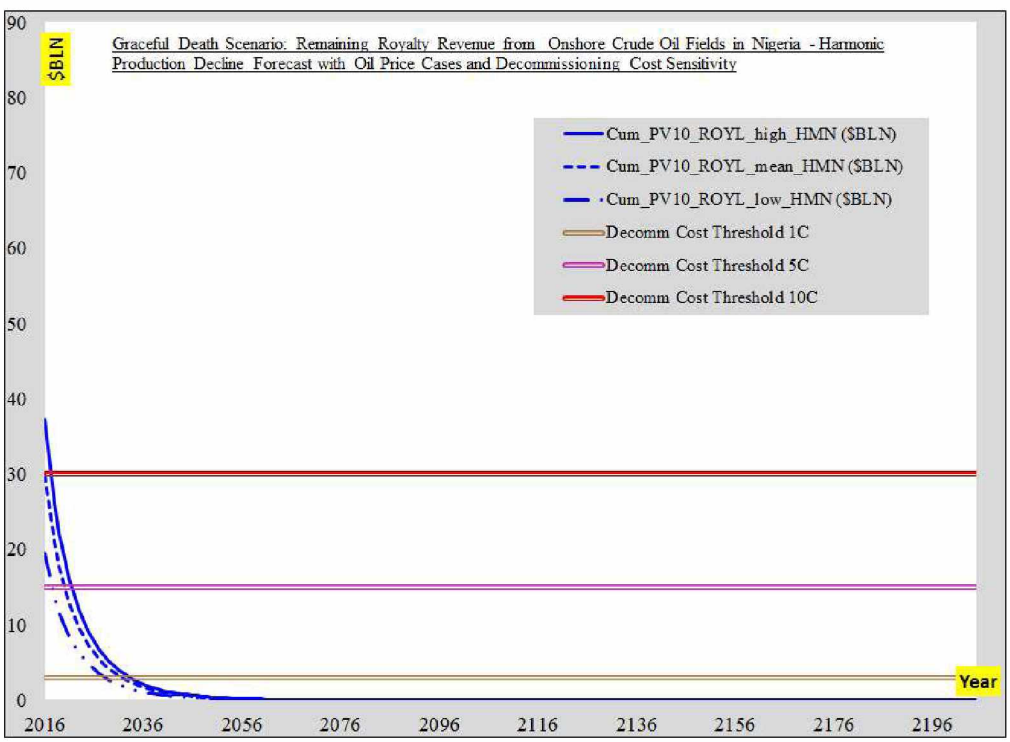
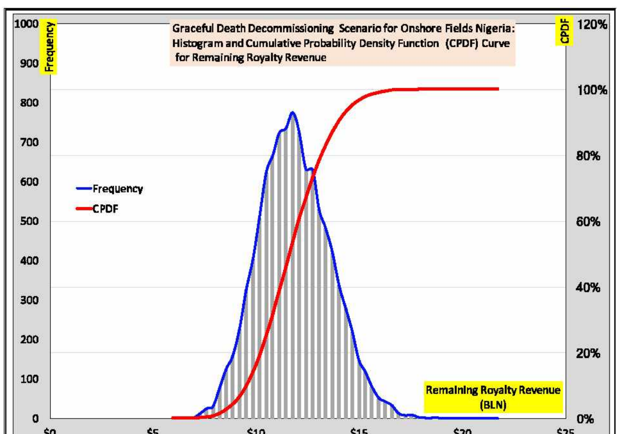


Figure 59: Graceful death scenario and harmonic production decline forecast – Present value of remaining royalty revenue and decommissioning cost thresholds for Nigerian onshore fields

(c.) Probabilistic Results: DCR from Remaining Royalty Revenue for Nigerian Onshore Crude Oil Fields

The probabilistic models evaluated the level of confidence around the deterministic DCR provided by royalties under both euthanasia and graceful death scenarios. The "b" factor in the hyperbolic DCA formula and P_c price per barrel of crude oil in the royalty revenue calculation (Equations 3 to 8) varied in stochastic evaluation using Monte Carlo simulation. The results are presented as a cumulative probability density function (CPDF) of the remaining royalty revenue and associated DCR tableau (Figure 60). The P90 and P10 DCR results and ranges based on the remaining tax revenue for both scenarios are less than 20, which further support the conclusion of a high vulnerability to decommissioning default risk for Nigerian onshore crude oil fields.



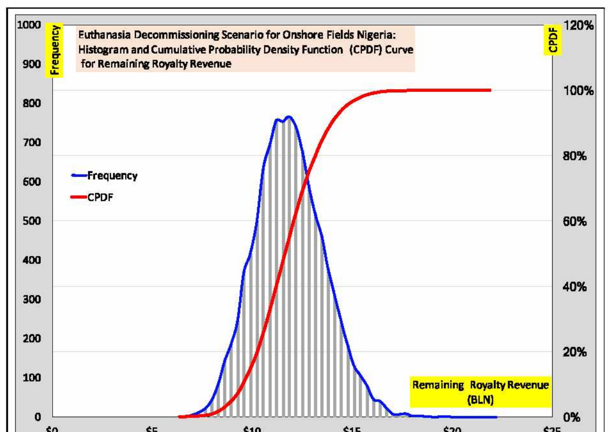
P90 Royalty Revenue Cost $BLN 14.0

P50 Royalty Revenue Cost $BLN 12.0

P10 Royalty Revenue Cost $BLN 10.0

DCRs:Remaining Royalty Revenue and Equal Chances of Occurrence for 1 to 10 times Decommissioning Cost of $3 billion

	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Expected DCR
P90	4.7	2.3	1.6	1.2	0.9	0.8	0.7	0.6	0.5	0.5	1.4
P50	4.0	2.0	1.3	1.0	0.8	0.7	0.6	0.5	0.4	0.4	1.2
P10	3.3	1.7	1.1	0.8	0.7	0.6	0.5	0.4	0.4	0.3	1.0



P90 Royalty Revenue $BLN 14.0

P50 Royalty Revenue $BLN 12.0

P10 Royalty Revenue $BLN 10.0

DCRs:Remaining Royalty Revenue and Equal Chances of Occurrence for 1 to 10 times Decommissioning Cost of $3 billion

	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Expected DCR
P90	4.7	2.3	1.6	1.2	0.9	0.8	0.7	0.6	0.5	0.5	1.4
P50	4.0	2.0	1.3	1.0	0.8	0.7	0.6	0.5	0.4	0.4	1.2
P10	3.3	1.7	1.1	0.8	0.7	0.6	0.5	0.4	0.4	0.3	1.0

Figure 60: Decommissioning scenarios for Nigerian onshore fields – Probabilistic remaining royalty revenue DCR results

9.4.2. Euthanasia and Graceful Death Scenarios: Results for Remaining JV Profit Share Revenue Stream

(a.) Decommissioning Coverage Ratio (DCR): Deterministic Results for Remaining JV Profit Share Revenue from Onshore Crude Oil Fields in Nigeria

Euthanasia Scenario: Remaining JV Profit Share Decommissioning Coverage Ratio (DCR) and Decommissioning Covergage Ratio vector (DCRV) Aggregrated for Nigerian Onshore Crude Oil Fields

Exponential Decline Curve		Decommmissioning Coverage Ratio *DCR_taxes*											Decommmissioning Coverage Ratio Vector *DCRV_taxes*										
Remaining Tax Revenue ($BLN)	Cost *C* / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
6.75	$82.60	2.3	1.1	0.8	0.6	0.5	0.4	0.3	0.3	0.3	0.2	0.7	2	0	0	0	0	0	0	0	0	0	0.2
4.98	$66.38	1.7	0.8	0.6	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.5	0	0	0	0	0	0	0	0	0	0	0.0
2.46	$43.30	0.8	0.4	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0	0	0	0	0	0	0	0	0	0	0.0
Weighted Average		1.6	0.8	0.5	0.4	0.3	0.3	0.2	0.2	0.2	0.2	**0.5**	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.1**

Harmonic Decline Curve		Decommmissioning Coverage Ratio *DCR_taxes*											Decommmissioning Coverage Ratio Vector *DCRV_taxes*										
Remaining Tax Revenue ($BLN)	Cost *C* / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
9.11	$82.60	3.0	1.5	1.0	0.8	0.6	0.5	0.4	0.4	0.3	0.3	0.9	4	0	0	0	0	0	0	0	0	0	0.4
6.70	$66.38	2.2	1.1	0.7	0.6	0.4	0.4	0.3	0.3	0.2	0.2	0.7	2	0	0	0	0	0	0	0	0	0	0.2
3.27	$43.30	1.1	0.5	0.4	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.3	0	0	0	0	0	0	0	0	0	0	0.0
Weighted Average		2.1	1.1	0.7	0.5	0.4	0.4	0.3	0.3	0.2	0.2	**0.6**	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.2**

Figure 61: Euthanasia scenario for Nigerian onshore fields – Deterministic DCR and DCRV with JV profit

Graceful Death Scenario: Remaining JV Profit Share Decommissioning Coverage Ratio (DCR) and Decommissioning Coverage Ratio vector (DCRV) Aggregrated for Nigerian Onshore Crude Oil Fields

Exponential Decline Curve		Decommmissioning Coverage Ratio *DCR_taxes*											Decommmissioning Coverage Ratio Vector *DCRV_taxes*										
Remaining Tax Revenue ($BLN)	Cost *C* / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
6.75	$82.60	2.3	1.1	0.8	0.6	0.5	0.4	0.3	0.3	0.3	0.2	0.7	2	0	0	0	0	0	0	0	0	0	0.2
4.98	$66.38	1.7	0.8	0.6	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.5	0	0	0	0	0	0	0	0	0	0	0.0
2.46	$43.30	0.8	0.4	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0	0	0	0	0	0	0	0	0	0	0.0
Weighted Average		1.6	0.8	0.5	0.4	0.3	0.3	0.2	0.2	0.2	0.2	**0.5**	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.1**

Harmonic Decline Curve		Decommmissioning Coverage Ratio *DCR_taxes*											Decommmissioning Coverage Ratio Vector *DCRV_taxes*										
Remaining Tax Revenue ($BLN)	Cost *C* / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
9.12	$82.60	3.0	1.5	1.0	0.8	0.6	0.5	0.4	0.4	0.3	0.3	0.9	4	0	0	0	0	0	0	0	0	0	0.4
6.70	$66.38	2.2	1.1	0.7	0.6	0.4	0.4	0.3	0.3	0.2	0.2	0.7	2	0	0	0	0	0	0	0	0	0	0.2
3.27	$43.30	1.1	0.5	0.4	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.3	0	0	0	0	0	0	0	0	0	0	0.0
Weighted Average		2.1	1.1	0.7	0.5	0.4	0.4	0.3	0.3	0.2	0.2	**0.6**	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.2**

Figure 62: Graceful death scenario for Nigerian onshore fields – Deterministic DCR and DCRV with JV profit

Decommissioning cost "C" of $30million per facility for a 100 facilities, aggregrated cost C = $3 BLN	
Key for DCR	**Key for DCRV**
DCR > or = 20 :Low Risk	DCRV > or = 40 :Low Urgency
20 > DCR > 10 :Medium Risk	40 > DCRV > 30 :Medium Urgency
DCR = or < 10 :High Risk	DCRV = or < 30 :High Urgency

Figure 63: Criteria and key to DCR and DCRV metrics

Similar to the remaining royalty revenue case, for the remaining JV profit share revenue, expected values of DCR for both scenarios range from 0.5 to 0.6 and for the individual deterministic cases, they range from 0.1 to 3.0 (Figure 61 – 63), which indicate high vulnerability to decommissioning default risk. None of the deterministic cases of coverage for decommissioning liabilities provided by JV profit share had a DCR greater than 20, which is the threshold for low vulnerability position. Therefore, given the results, vulnerability to decommissioning default risk can be considered high for Nigerian onshore crude oil fields. There is no significant difference between results from both scenarios, showing that irrespective of the future decommissioning scenario, vulnerability to decommissioning default risk is already high.

(b.)Decommissioning Coverage Ratio Vector (DCRV) Results: Remaining JV Profit Share

The expected values of DCRV for both scenarios range from 0.1 to 0.2, which show an imminence of vulnerability to decommissioning default risk events and high urgency for decommissioning policy development and readiness plan. There is no significant difference between similar cases under both scenarios and none of the individual cases have a DCRV greater than 40, which is the threshold for low urgency situation and a comfortable decommissioning policy development lead time.

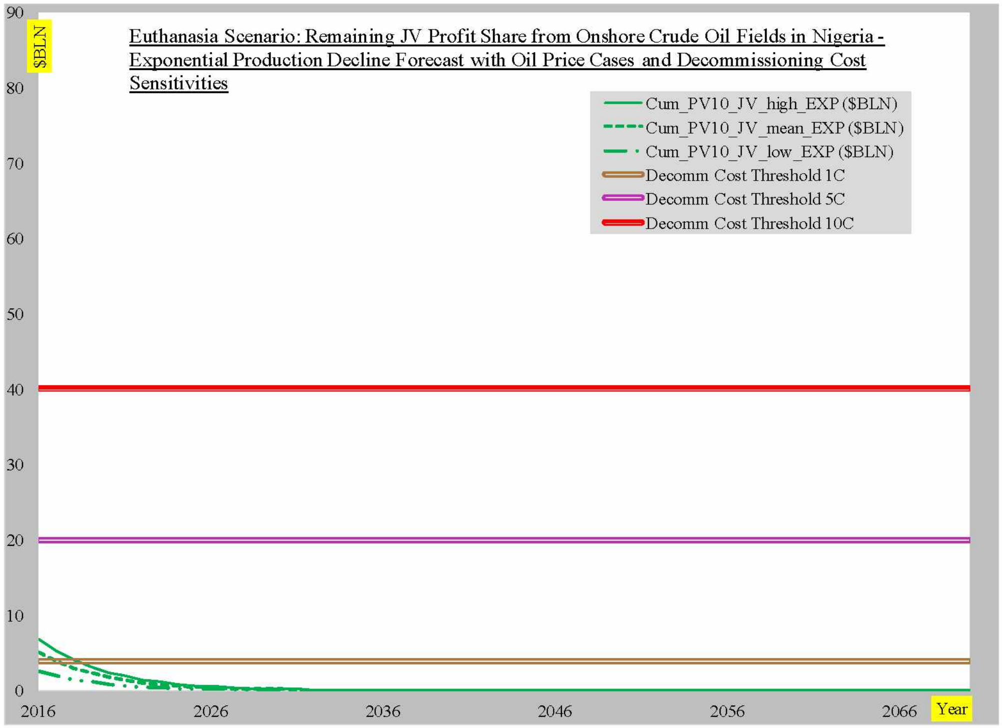


Figure 64: Euthanasia scenario and exponential production decline forecast - Present value of remaining JV profit share revenue and decommissioning cost thresholds for Nigerian onshore fields

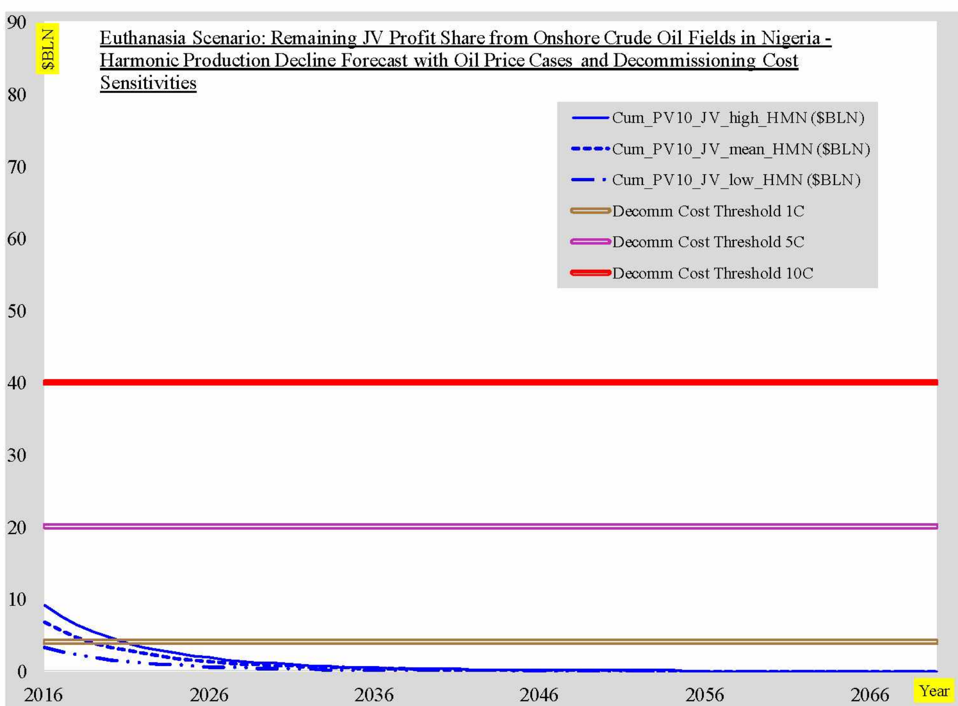


Figure 65: Euthanasia scenario and harmonic production decline forecast – Present value of remaining JV profit share revenue and decommissioning cost thresholds for Nigerian onshore fields

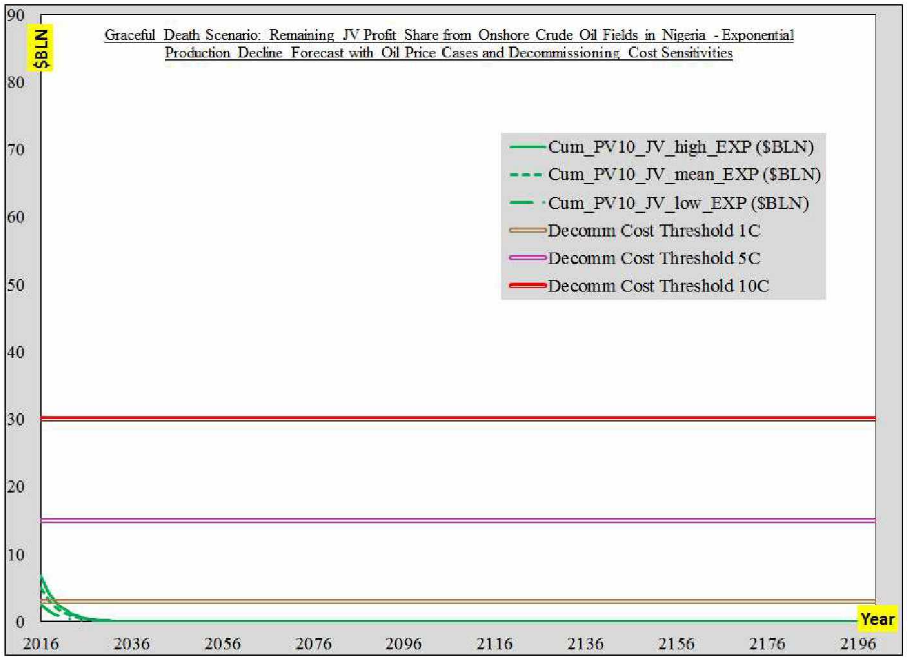


Figure 66: Graceful death scenario and exponential production decline forecast – Present value of remaining JV profit share revenue and decommissioning cost thresholds for Nigerian onshore fields

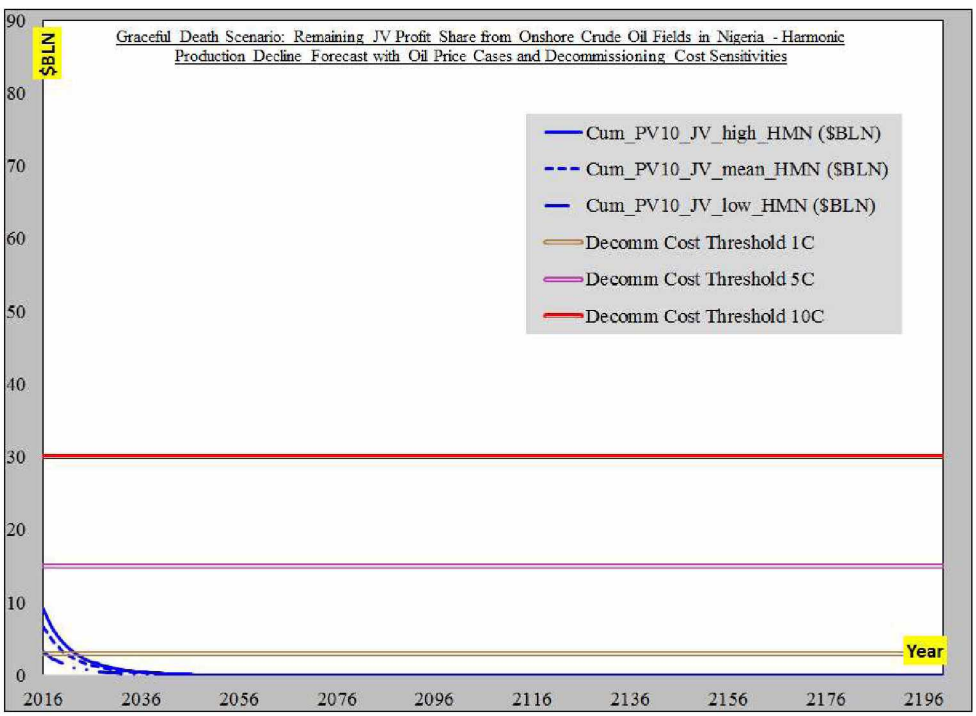
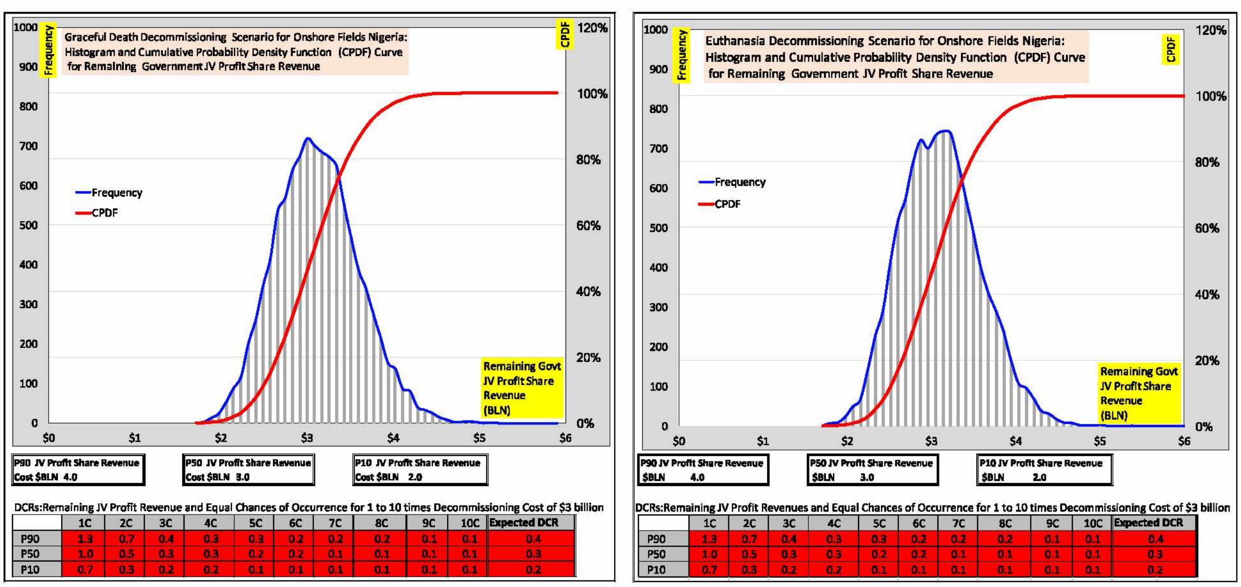


Figure 67: Graceful death scenario and harmonic production decline forecast – Present value of remaining JV profit share revenue and decommissioning cost thresholds for Nigerian onshore fields

The DCRV can also be represented as the intercept between decommissioning cost threshold plot and the PV of the remaining JV profit share revenue plot – a depiction of DCRV which is the number of years between 2016 and time when the PV of the remaining JV profit share revenue will be equal to the decommissioning cost (Figures 64 – 67).

(c.) Probabilistic Results: DCR from Remaining JV Profit Share for Nigerian Onshore Crude Oil Fields

The probabilistic models evaluated the level of confidence around the deterministic DCR results for both the selected scenarios. The "b" factor in the hyperbolic DCA formula and $\boldsymbol{P_c}$, the price per barrel of crude oil in the JV profit share revenue calculation (Equations 3 to 8) were varied in stochastic evaluation using Monte Carlo simulation. The results are presented as a CPDF of the remaining tax revenue and associated DCR tableau (Figure 68). The P90 and P10 DCR results and ranges based on the remaining JV profit share revenue for both scenarios are less than 20, which further support the conclusion of a high vulnerability to decommissioning default risk for Nigerian onshore crude oil fields.



	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Expected DCR
P90	1.3	0.7	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.4
P50	1.0	0.5	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.3
P10	0.7	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2

	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Expected DCR
P90	1.3	0.7	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.4
P50	1.0	0.5	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.3
P10	0.7	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2

Figure 68: Decommissioning scenarios for Nigerian onshore fields – Probabilistic remaining JV profit share revenue DCR results

9.4.3. Euthanasia and Graceful Death Scenarios: Results for Remaining Tax Revenue Stream

(a.) Decommissioning Coverage Ratio (DCR): Deterministic Results for Remaining Tax Revenue from Onshore Crude Oil Fields in Nigeria

Euthanasia Scenario: Remaining Tax Revenue Decommissioning Coverage Ratio (DCR) and Decommissioning Covergage Ratio vector (DCRV) Aggregrated for Nigerian Onshore Crude Oil Fields

Exponential Decline Curve		Decommmissioning Coverage Ratio DCR_taxes											Decommmissioning Coverage Ratio Vector DCRV_taxes										
Remaining Tax Revenue ($BLN)	Cost C / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
36.83	$82.60	13.7	6.9	4.6	3.4	2.7	2.3	2.0	1.7	1.5	1.4	4.0	10	8	6	5	4	3	2	2	1	1	4.2
27.17	$66.38	10.5	5.2	3.5	2.6	2.1	1.7	1.5	1.3	1.2	1.0	3.1	9	6	5	4	3	2	1	1	0	0	3.1
13.42	$43.30	5.9	3.0	2.0	1.5	1.2	1.0	0.8	0.7	0.7	0.6	1.7	7	4	2	1	0	0	0	0	0	0	1.4
Weighted Average		10.0	5.0	3.3	2.5	2.0	1.7	1.4	1.3	1.1	1.0	**2.9**	8.7	6.0	4.3	3.3	2.3	1.7	1.0	1.0	0.3	0.3	**2.9**

Harmonic Decline Curve		Decommmissioning Coverage Ratio DCR_taxes											Decommmissioning Coverage Ratio Vector DCRV_taxes										
Remaining Tax Revenue ($BLN)	Cost C / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
48.59	$82.60	18.2	9.1	6.1	4.5	3.6	3.0	2.6	2.3	2.0	1.8	5.3	19	14	11	9	8	6C	5	4	4	3	8.6
35.73	$66.38	13.9	6.9	4.6	3.5	2.8	2.3	2.0	1.7	1.5	1.4	4.1	17	12	9	7	6	5	4	3	2	1	6.6
17.44	$43.30	7.8	3.9	2.6	1.9	1.6	1.3	1.1	1.0	0.9	0.8	2.3	13	8	5	3	2	1	0	0	0	0	3.2
Weighted Average		13.3	6.6	4.4	3.3	2.7	2.2	1.9	1.7	1.5	1.3	**3.9**	16.3	11.3	8.3	6.3	5.3	3.0	3.0	2.3	2.0	1.3	**5.9**

Figure 69: Euthanasia scenario for Nigerian onshore fields – Deterministic DCR and DCRV with tax revenue

Graceful Death Scenario: Remaining Tax Revenue Decommissioning Coverage Ratio (DCR) and Decommissioning Coverage Ratio vector (DCRV) Aggregrated for Nigerian Onshore Crude Oil Fields

Exponential Decline Curve		Decommmissioning Coverage Ratio DCR_taxes											Decommmissioning Coverage Ratio Vector DCRV_taxes										
Remaining Tax Revenue ($BLN)	Cost C / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
36.83	$82.60	13.7	6.9	4.6	3.4	2.7	2.3	2.0	1.7	1.5	1.4	4.0	10	8	6	5	4	3	2	2	1	1	4.2
27.17	$66.38	10.5	5.2	3.5	2.6	2.1	1.7	1.5	1.3	1.2	1.0	3.1	9	6	5	4	3	2	1	1	0	0	3.1
13.42	$43.30	5.9	3.0	2.0	1.5	1.2	1.0	0.8	0.7	0.7	0.6	1.7	7	4	2	1	0	0	0	0	0	0	1.4
Weighted Average		10.0	5.0	3.3	2.5	2.0	1.7	1.4	1.3	1.1	1.0	**2.9**	8.7	6.0	4.3	3.3	2.3	1.7	1.0	1.0	0.3	0.3	**2.9**

Harmonic Decline Curve		Decommmissioning Coverage Ratio DCR_taxes											Decommmissioning Coverage Ratio Vector DCRV_taxes										
Remaining Tax Revenue ($BLN)	Cost C / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
48.62	$82.60	18.2	9.1	6.1	4.5	3.6	3.0	2.6	2.3	2.0	1.8	5.3	20	14	11	9	8	6	5	4	4	3	8.4
35.75	$66.38	13.9	6.9	4.6	3.5	2.8	2.3	2.0	1.7	1.5	1.4	4.1	17	12	9	7	6	5	4	3	2	1	6.6
17.44	$43.30	7.8	3.9	2.6	1.9	1.6	1.3	1.1	1.0	0.9	0.8	2.3	13	8	5	3	2	1	0	0	0	0	3.2
Weighted Average		13.3	6.6	4.4	3.3	2.7	2.2	1.9	1.7	1.5	1.3	**3.9**	16.7	11.3	8.3	6.3	5.3	4.0	3.0	2.3	2.0	1.3	**6.1**

Figure 70: Graceful death scenario for Nigerian onshore fields – Deterministic DCR and DCRV with tax revenue

Decommissioning cost "C" of $30million per facility for a 100 facilities, aggregrated cost C = $3 BLN	
Key for DCR	**Key for DCRV**
DCR > or = 20 :Low Risk	DCRV > or = 40 :Low Urgency
20 > DCR > 10 :Medium Risk	40 > DCRV > 30 :Medium Urgency
DCR = or < 10 :High Risk	DCRV = or < 30 :High Urgency

Figure 71: Criteria and key to DCR and DCRV metrics

The expected values of DCR based on remaining tax revenue for both scenarios range from 2.9 to 3.9 and for the individual deterministic cases, they range from 2.0 to 5.0 (Figures 69 - 71), which indicate high vulnerability to decommissioning default risk. None of the deterministic cases had a DCR greater than 20, which is the threshold for low vulnerability position. Therefore, given the results, vulnerability to decommissioning default risk can be considered high for Nigerian onshore crude oil fields. There is no significant difference between the results from both scenarios, showing that irrespective of the future decommissioning scenario, vulnerability to decommissioning default risk is already high.

(b.)Decommissioning Coverage Ratio Vector (DCRV) Results: Remaining Tax Revenue

The expected values of DCRV for both scenarios range from 3.2 to 13.6 (Figures 69 - 71), which show an imminence of vulnerability to decommissioning default risk events and high urgency for decommissioning policy development and readiness plan. There is no significant difference between similar cases under both scenarios and none of the individual cases have a DCRV greater than 40, which is the threshold for low urgency situation and a comfortable decommissioning policy development lead time.

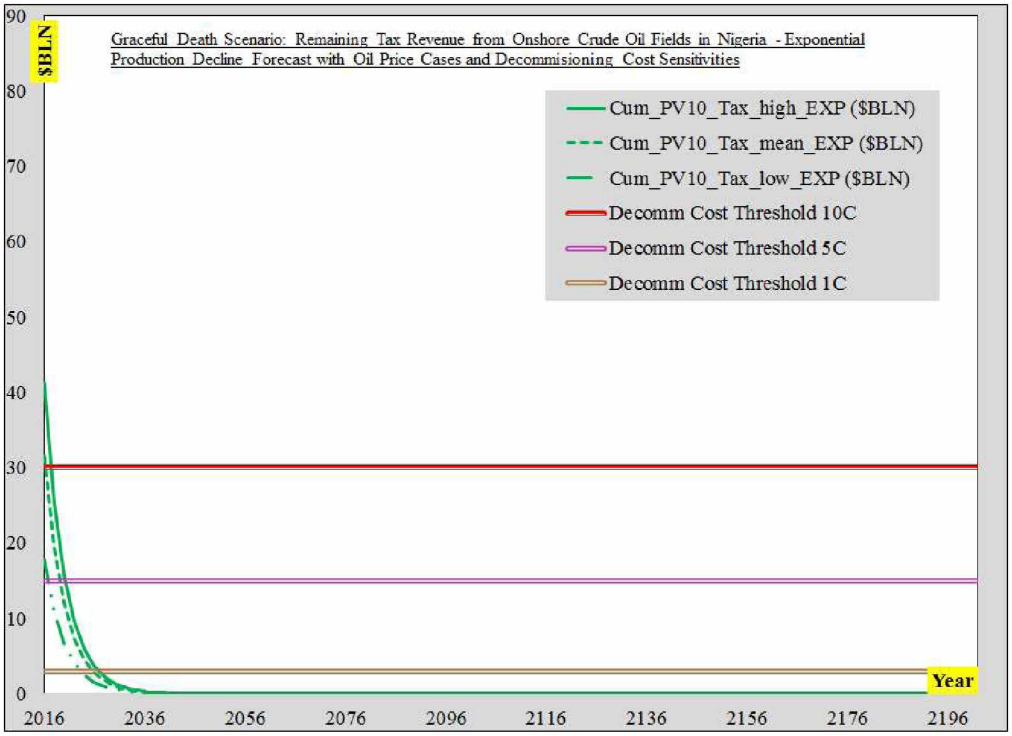


Figure 72: Graceful death scenario and exponential production decline forecast – Present value of remaining tax revenue and decommissioning cost thresholds for Nigerian onshore fields

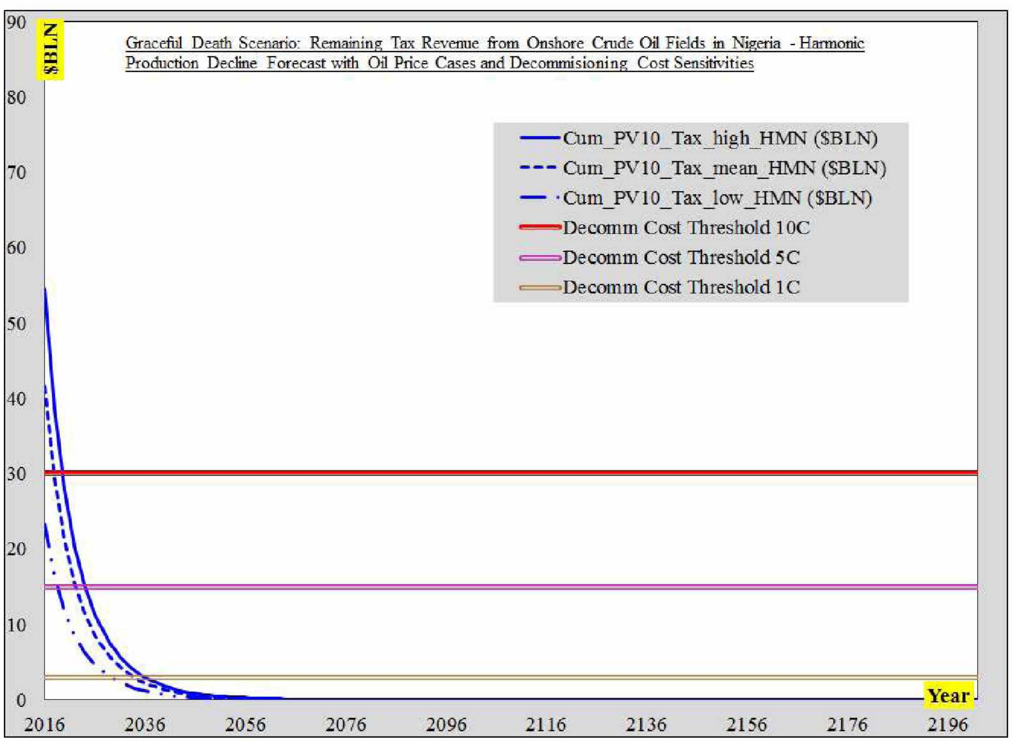


Figure 73: Graceful death scenario and harmonic production decline forecast – Present value of remaining tax revenue and decommissioning cost thresholds for Nigerian onshore fields

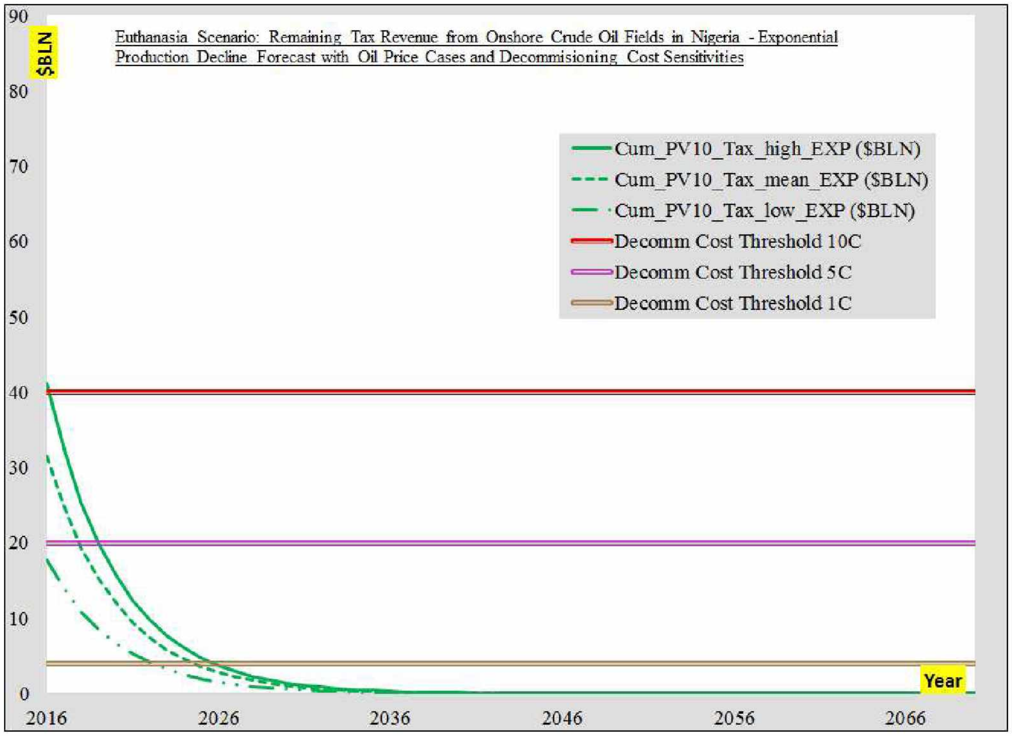


Figure 74: Euthanasia death scenario and exponential production decline forecast – Present value of remaining tax revenue and decommissioning cost thresholds for Nigerian onshore fields

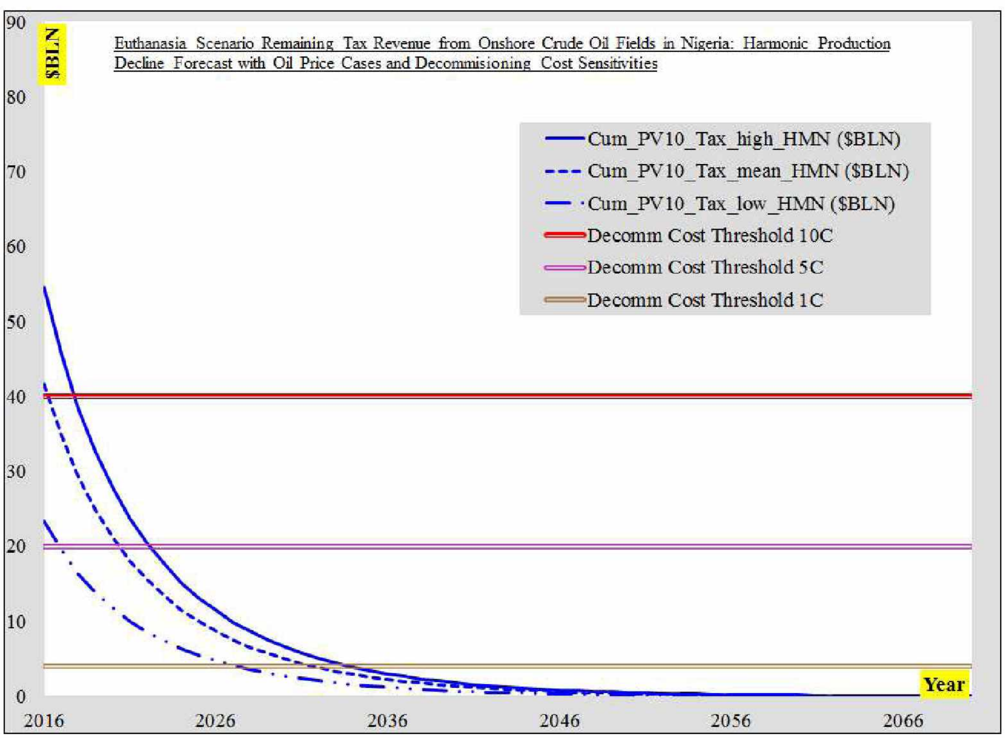


Figure 75: Euthanasia death scenario and harmonic production decline forecast – Present value of remaining tax revenue and decommissioning cost thresholds for Nigerian onshore fields

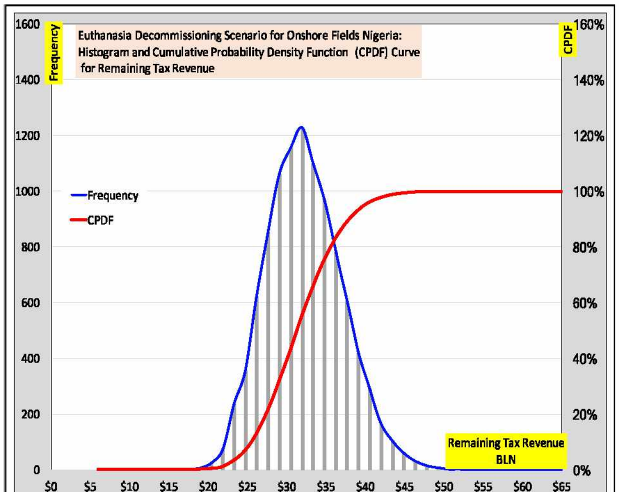
The DCRV is also represented as the intercept between decommissioning cost threshold plot and the PV of the remaining tax revenue plot – a depiction of DCRV, which is the number of years between 2016 and time when the PV of the remaining tax revenue will be equal to the decommissioning cost (Figures 72–75).

Using different cases that could cover the plausible range of cost of decommissioning liabilities for onshore crude oil fields in Nigeria (Figures 72 and 73 for graceful death scenarios and Figures 74 and 75 for euthanasia scenarios) demonstrates that in a no distance future, the remaining revenue from royalties may not adequately cover the cost of decommissioning liabilities.

Therefore, there is an urgent need to commence decommissioning policy development and readiness plan for Nigerian onshore crude oil fields. As demonstrated, a combination of DCR and DCRV provides an indication of vulnerability and imminence of decommissioning default risk, and how soon a mitigation is needed. Combined, they provide better justification to commence planning for decommissioning compared to use for only asset coverage ratios, such as CDR and ADR.

(c.) Probabilistic Results: DCR from Remaining JV Profit Share for Nigerian Onshore Crude Oil Fields

The probabilistic models evaluated the level of confidence around the deterministic DCR results for both the selected scenarios. The "b" factor in the DCA formula and P_c, the price per barrel of crude oil in the tax revenue calculation (Equations 9, 10, 19, 20 & 21), were varied in stochastic evaluation using Monte Carlo simulation. The results are presented as a CPDF of the remaining tax revenue and associated DCR tableau (Figure 76). The P90 and P10 DCR results and ranges based on the remaining tax revenue for both scenarios are less than 20, which further support the conclusion of a high vulnerability to decommissioning default risk for Nigerian onshore crude oil fields.



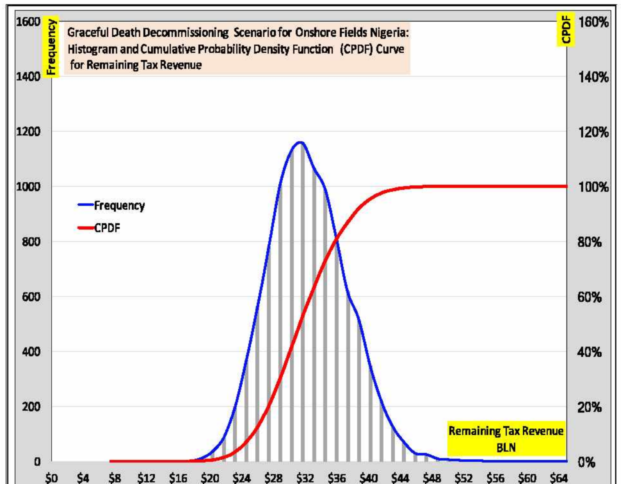
P90 Tax Revenue $BLN 39.0

P50 Tax Revenue $BLN 32.0

P10 Tax Revenue $BLN 25.0

DCRs:Remaining Tax Revenues and Equal Chances of Occurrence for 1 to 10 times Decommissioning Cost of $3 billion

	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Expected DCR
P90	13.0	6.5	4.3	3.3	2.6	2.2	1.9	1.6	1.4	1.3	3.8
P50	10.7	5.3	3.6	2.7	2.1	1.8	1.5	1.3	1.2	1.1	3.1
P10	8.3	4.2	2.8	2.1	1.7	1.4	1.2	1.0	0.9	0.8	2.4



P90 Tax Revenue Cost $BLN 39.0

P50 Tax Revenue Cost $BLN 32.0

P10 Tax Revenue Cost $BLN 26.0

DCRs:Remaining Tax Revenues and Equal Chances of Occurrence for 1 to 10 times Decommissioning Cost of $3 billion

	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Expected DCR
P90	13.0	6.5	4.3	3.3	2.6	2.2	1.9	1.6	1.4	1.3	3.8
P50	10.7	5.3	3.6	2.7	2.1	1.8	1.5	1.3	1.2	1.1	3.1
P10	8.7	4.3	2.9	2.2	1.7	1.4	1.2	1.1	1.0	0.9	2.5

Figure 76: Decommissioning scenarios for Nigerian onshore fields – Probabilistic remaining tax revenue DCR results

9.4.4. Sudden Death Scenario: Results for Remaining Net Operating Revenue Stream

(a.) Deterministic Decommissioning Coverage Ratio (DCR): Deterministic Results for Remaining Net Revenue from Onshore Crude Oil Fields in Nigeria

Considering a sudden death scenario, the entire net operating profit before deduction for taxes and other non-operating expenses will be the key focus. The government will have it all, both revenues and liabilities. Unlike the other two scenarios without a single individual deterministic case result of DCR more than 20, there are results for a few individual situations with DCR above 20. For example, with a high oil price case and low decommissioning cost, the DCR will be 34, which represents a low vulnerability to decommissioning default risk (Figure 77). However, over a wide range of price and cost estimates ranges and for most of the individual deterministic cases, under either pessimistic exponential DCA or optimistic harmonic DCA, the expected value of DCR is less than 20, which represents a high vulnerability to decommissioning default risk for this scenario. The resources have been depleted to a level where irrespective of the times of exit, there will be challenges with adequate revenue to pay for the proper decommissioning of these fields.

Sudden Death Scenario: Remaining Operating Revenue Decommissioning Coverage Ratio (DCR) and Decommissioning Covergage Ratio vector (DCRV) Aggregrated for Nigerian Onshore Crude Oil Fields

Exponential Decline Curve		Decommmissioning Coverage Ratio						*DCR_Net_Operating Revenue*					Decommmissioning Coverage Ratio Vector						*DCR_Net_Operating Revenue*				
Remaining Tax Revenue ($BLN)	Cost *C* / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
27.32	$82.60	34.1	17.1	11.4	8.5	6.8	5.7	4.9	4.3	3.8	3.4	10.0	13	11	9	8	7	6	6	5	5	4	7.4
21.96	$66.38	25.2	12.6	8.4	6.3	5.0	4.2	3.6	3.1	2.8	2.5	7.4	12	9	8	7	6	5	5	4	4	3	6.3
14.32	$43.30	12.4	6.2	4.1	3.1	2.5	2.1	1.8	1.6	1.4	1.2	3.6	9	7	5	4	3	2	2	1	1	0	3.4
	Average	23.9	12.0	8.0	6.0	4.8	4.0	3.4	3.0	2.7	2.4	**7.0**	11.3	9.0	7.3	6.3	5.3	4.3	4.3	3.3	3.3	2.3	**5.7**

Harmonic Decline Curve		Decommmissioning Coverage Ratio						*DCR_Net_Operating Revenue*					Decommmissioning Coverage Ratio Vector						*DCR_Net_Operating Revenue*				
Remaining Tax Revenue ($BLN)	Cost *C* / Price $/bbl	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Weighted Average
37.23	$82.60	46.0	23.0	15.3	11.5	9.2	7.7	6.6	5.8	5.1	4.6	13.5	26	21	18	16	14	13	11	11	10	9	14.9
29.92	$66.38	33.9	16.9	11.3	8.5	6.8	5.6	4.8	4.2	3.8	3.4	9.9	24	18	15	13	12	10	9	8	8	7	12.4
19.51	$43.30	16.5	8.3	5.5	4.1	3.3	2.8	2.4	2.1	1.8	1.7	4.8	17	12	10	8	6	5	4	4	3	2	7.1
Weighted Average		32.1	16.1	10.7	8.0	6.4	5.4	4.6	4.0	3.6	3.2	**9.4**	22.3	17.0	14.3	12.3	10.7	9.3	8.0	7.7	7.0	6.0	**11.5**

Figure 77: Sudden death scenario in Nigerian onshore fields – Deterministic DCR and DCRV with remaining net operating revenue

Decommissioning cost "C" of $30million per facility for a 100 facilities, aggregrated cost C = $3 BLN

Key for DCR	**Key for DCRV**
DCR > or = 20 :Low Risk	DCRV > or = 40 :Low Urgency
20 > DCR > 10 :Medium Risk	40 > DCRV > 30 :Medium Urgency
DCR = or < 10 :High Risk	DCRV = or < 30 :High Urgency

Figure 78: Criteria and key to DCR and DCRV metrics

The sudden death scenario is analogous to a situation where somebody dies suddenly without any premonition or ignored premonition. The deceased dies intestate leaving behind no will, no instruction, and the estate is not robust. The government will take over the estate which is almost toxic, operates it, and pays for all outstanding obligations left behind by the recent operator. With oil fields, the outstanding obligations left behind will include the decommissioning activities. While the entire revenue after paying for expenses will be available to the government, at this time with decline in production, the entire revenue may not cover the cost of decommissioning the fields.

(b.)Decommissioning Coverage Ratio Vector (DCRV) Results: Remaining Net Revenue

The DCRV is a representation of the imminence of decommissioning default risk for an entity under considerations. For the case study Nigerian onshore crude oil fields, the threshold DCRV < 30, represents a non-desirable threshold of approximately 30 years or less before the remaining revenue will not be adequate to cover the cost of decommissioning liabilities. From the results (Figure 77 and 78), there are only few individual cases that did not fall below the threshold, representing a high imminence of decommissioning default risk. Considering equal chances of occurrence of high, medium, and low-price cases and the actual cost of decommissioning liabilities being one to ten times the estimated cost, the DCRV for euthanasia and harmonic DCA production cases are 9.4 and 11.5, respectively (Figure 77 and 78). This is below the threshold DCRV of 30, which implies a high imminence of (or few years to) decommissioning default risk for Nigerian onshore crude oil fields under this scenario, irrespective of the production DCA method considered (Figures 79 and 80). The time left before decommissioning default risk takes place in Nigerian onshore crude oil region is not much..

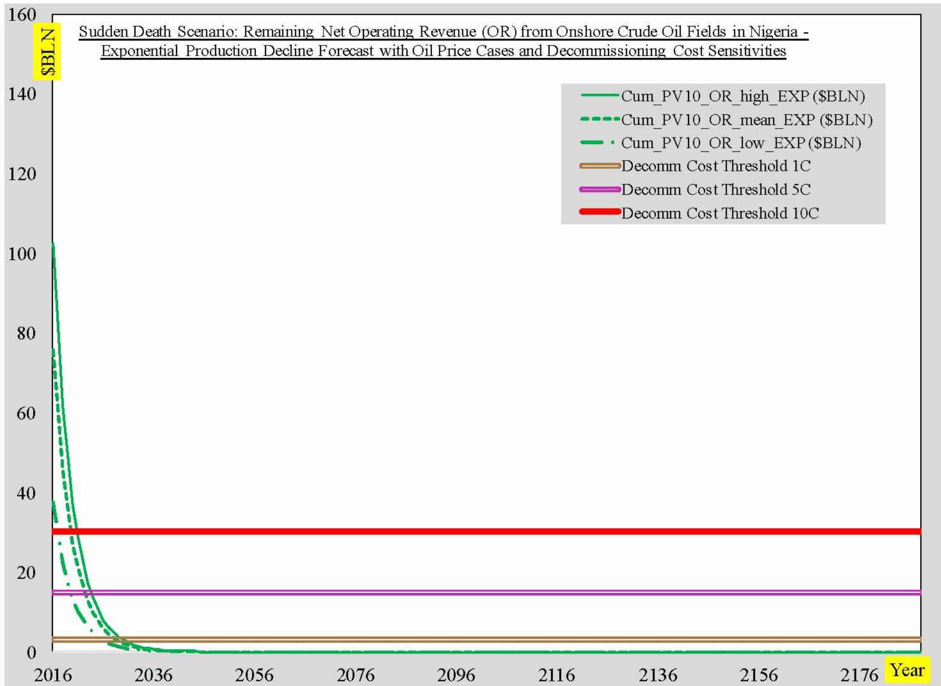


Figure 79: Sudden death scenario and exponential production decline forecast – Present value of remaining net operating profit and decommissioning cost thresholds for Nigerian onshore fields

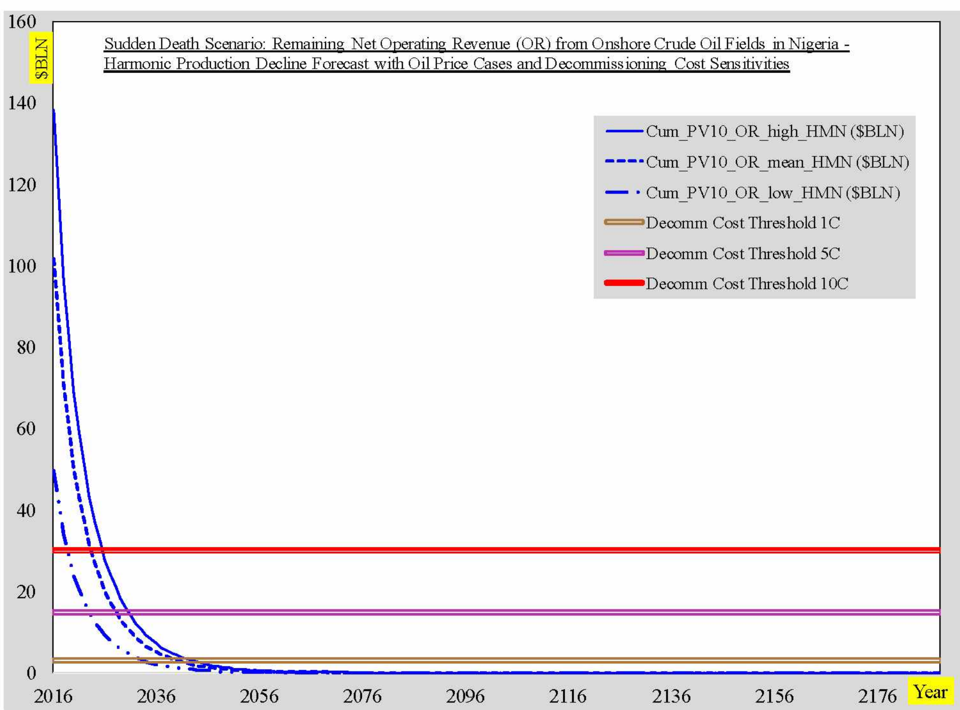
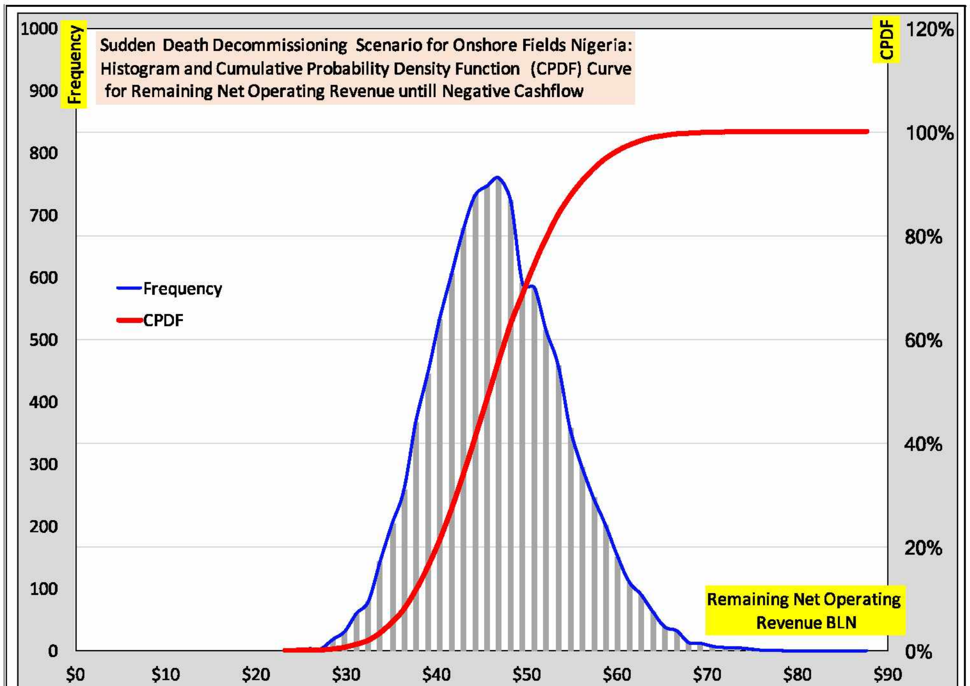


Figure 80: Sudden death scenario and harmonic production decline forecast – Present value of remaining net operating profit and decommissioning cost thresholds for Nigerian onshore fields

(c.) Probabilistic Results: DCR from Remaining Net Revenue for Nigerian Onshore Crude Oil Fields



P90 Net Operating Revenue Cost $BLN 56.0

P50 Net Operating Revenue Cost $BLN 46.0

P10 Net Operating Revenue Cost $BLN 38.0

DCRs:Remaining Net Operating Revenues(gross revenue less direct operating cost only) and Equal Chances of Occ Decommissioning Cost of $3 billion

	1C	2C	3C	4C	5C	6C	7C	8C	9C	10C	Expected DCR
P90	18.7	9.3	6.2	4.7	3.7	3.1	2.7	2.3	2.1	1.9	5.5
P50	15.3	7.7	5.1	3.8	3.1	2.6	2.2	1.9	1.7	1.5	4.5
P10	12.7	6.3	4.2	3.2	2.5	2.1	1.8	1.6	1.4	1.3	3.7

Figure 81: Decommissioning scenarios for Nigerian onshore fields – Probabilistic remaining net operating profit revenue DCR results

The probabilistic analysis further supports the inference that the vulnerability is high. The P90, P50, and P10 values of DCR 5.5, 4.5, and 3.7 are below 20 (Figure 81), which supports the inference from the deterministic results that the vulnerability to decommissioning default risk is high for Nigerian onshore crude oil fields.

9.4.5. Summary of DCR and DCRV for Euthanasia and Graceful Death Scenarios

Considering all the scenarios, the vulnerability of Nigerian onshore crude oil fields to decommissioning default risk is high with none having an expected DCR value above 20 (Table 17). The imminence of a decommissioning default risk is also high given that none of the expected DCRV was up to 40 or higher (Table 17). It means that in less than 40 years, the remaining revenue from the crude oil fields under any revenue stream may not be able to cover the cost of decommissioning liabilities.

Table 17: Summary of DCR and DCRV results for Nigerian onshore fields

Scenario	Revenue Stream	Expected Value DCRV		Expected Value Deterministic DCR		Probabilistic DCR (P50)
		Exponential	Harmonic	Exponential	Harmonic	
Euthanasia	Royalty	**2.1**	**2.8**	**1.2**	**3.0**	**1.2**
	JV Profit Share	**0.5**	**0.6**	**0.1**	**0.2**	**0.3**
	Tax	**2.9**	**5.9**	**2.9**	**3.9**	**3.1**
Graceful Death	Royalty	**2.1**	**2.8**	**1.2**	**3.0**	**1.2**
	JV Profit Share	**0.5**	**0.6**	**0.1**	**0.2**	**0.3**
	Tax	**2.9**	**6.1**	**2.9**	**3.9**	**3.1**
Sudden Death	Net Operating Revenue	**5.7**	**11.5**	**7.0**	**9.4**	**4.5**

9.4.6. Results and Discussions from Further Sensitivity Analysis

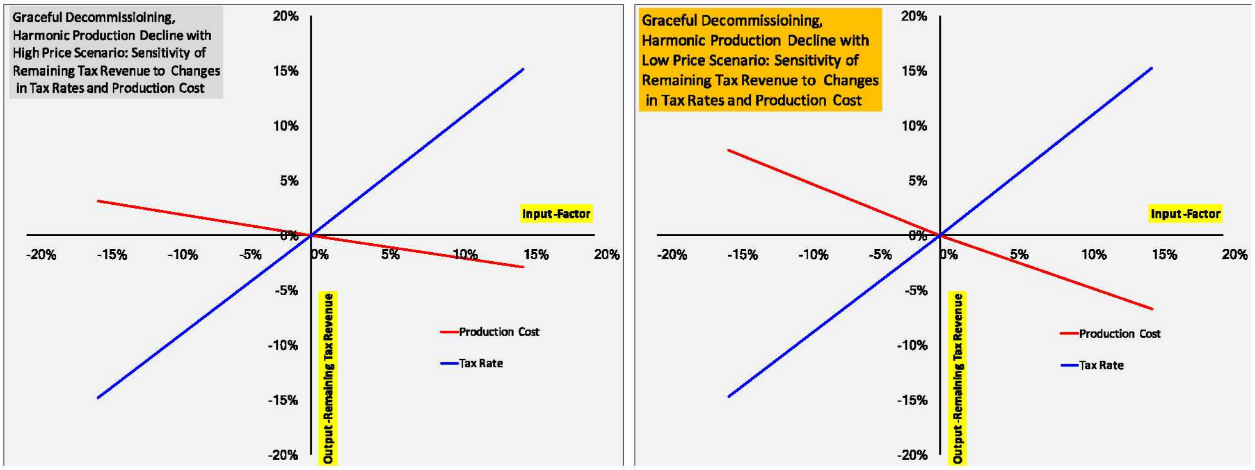


Figure 82: Sensitivity of input factors to tax revenue – High and low boundary conditions

The DCR is a function of decommissioning cost and remaining revenue. Decommissioning cost is outside the direct control of government and regulatory policy instruments. On the other hand, remaining tax revenue can be influenced by the government through changes to the tax rate and selection of operators with different operational efficiencies whose proxy is the production cost. However, from the sensitivity analysis (Figure 82), the DCR and remaining tax revenue are influenced more by the tax rate than production cost. Therefore, changes in operatorship do not influence vulnerability to decommissioning default risk as much as changes to the tax rate.

9.4.7. Interim Recommendations and Conclusions

The remaining tax revenue from Nigerian onshore crude oil fields may not be sufficient to provide a comfortable coverage for decommissioning cost of the fields. Based on the remaining tax revenue, none of the individual cases in the tableaus for both decommissioning scenarios have a DCR that is greater than 20, that is, 20 times the decommissioning cost.

Considering that divestments by MOCs to smaller companies is ongoing, the notorious legacy of pollution in the fields and potential for huge decommissioning cost over-run, this is a high vulnerability position to decommissioning default risk.

The urgency to develop a decommissioning policy and plan for onshore fields in Nigeria is high. None of the individual cases in the tableaus for both decommissioning scenarios has a DCRV of greater than 40, which indicates a time span of less than 40 years before the remaining tax revenue will be less than the decommissioning cost for the fields. For a country with a history of very slow pace of policy development and planning, Nigeria needs to commence the development of a sustainable decommissioning policy and plan as soon as possible.

The sensitivity analysis shows that the transfer of ownership to low cost producers or increase in operational efficiency may not singularly and significantly increase the remaining tax revenue accruable from the fields. Divestment to low cost producers may elongate the economic life of the fields, but tax rate is a more leveraging factor on remaining tax revenues. The use of lower tax rates to incentivize low cost operators in the late life of these fields may need to be critically evaluated as its effect on the remaining tax revenue may not be directly compensated by a decrease in production cost and elongation of economic life of the fields. Before any asset divestment is completed, the government may need to ensure that financial assurances are in place for decommissioning liabilities to provide coverage at an appropriate level of DCR.

This study demonstrated a new approach to decommissioning risk evaluation from the perspective of vulnerability to decommissioning default risk. It defined the metrics for the quantification of vulnerability to decommissioning default risk and imminence of its occurrence. The approach and metrics can be adapted to any region, country, or field to help guide decommissioning policy development and readiness plan.

9.4.8. Limitation and Further Studies for DCRV Model

Nigerian onshore crude oil production data were sourced from secondary sources and accuracy may be accordingly limited. In adopting the study results for policy planning, government agencies may need to validate and update results with data from primary sources. Similar evaluation based on other types of revenue streams, such as JV profit share and royalties, may provide additional information for better fiscal policy decisions for decommissioning.

9.5. Fairbanks Sustainable Decommissioning Maturity Model: Results and Discussions of Results for Nigerian Onshore Fields

Based on the information from web and publicly accessible domains, the current approach and practice of some identified nations or regions already with significant decommissioning activities either completed or on-going are as follows in Tables 17–24:

Table 18: Inventory of fields/ facilities for decommissioning monitoring

Region	Description of the current approach and performance
Alberta, Canada	Regulatory agency – Alberta Energy Regulator (AER): Inventory in the form of two MS Excel lists of facilities – active and inactive, are publicly accessible from the regulator's website and updated daily. Also, annual report ST102 contains information on operator's name, facility type, and status. In addition, the website provides a link to the Orphan Well Program website, which has a list of all orphan wells, pipeline and installation sites, including the last name of the last operators and licensees (www.aer.ca) (AER, 2017).
UKCS	Regulatory agency for decommissioning is the offshore petroleum regulator for environment and decommissioning (OPRED) under the Department of Business, Energy and Industrial Strategy (BEIS) and the government regulatory agency with oversight for growth of the industry is Oil and Gas Authority (OGA). Between the two agencies, there are free and publicly accessible files from the petroleum production reporting systems (PPRS), with information on the list of offshore fields in production and first production date, wells and detail information on each well, and production history. The data set is updated at least quarterly. (www.ogauthority.co.uk) (OGA, 2017).
OCS	Regulatory and licensing agencies BSEE and BOEM have files containing a list of offshore fields and platforms, and production of each platform, accessible to the public for free, from the agencies websites (www.data.bsee.gov) (BSEE, 2017) and (www.data.boem.gov) (BOEM, 2017). There is no information on size of facilities.
Nigeria	Regulatory agency, DPR has lists of oil blocks and their operators from 2013 to 2016, in its annual oil and gas industry reports, published and publicly accessible for free, on its websites. The lists do not contain information on installed crude oil facilities and wells. However, information on gas facilities are listed in the reports. There are inconsistent lists of fields, platforms, and associated data on operators and year of installation on NNPC and Ministry of Petroleum and Energy (MPE) websites.

Table 19: Cost of decommissioning liabilities

Region	Description of current approach and performance
Alberta, Canada	Cost of decommissioning liabilities per field or assets was not published on the company website. However, the total cost for all the fields and unit rates for standardized unit of decommissioning scope of work were published in a basis of estimate document and updated regularly. AER's approach is to use these unit rates as building blocks to generate the cost of decommissioning liabilities for its facilities, except where an operator could justify otherwise (www.aer.ca) (AER, 2017). 2016 estimate was provided as $31 billion for the entire region.
UKCS	Cost of decommissioning liabilities per field or assets was not published on the company website. However, the total cost for all the fields was published annually. OGA conducts a survey amongst operators in UKCS for data before applying probabilistic techniques to determine the P90, P50, and P10 cost estimates. (www.ogauthority.co.uk) (OGA, 2017). P50 estimate in 2016 dollars was $59.7 billion for UKCS.
OCS	Cost estimates at individual asset level was done by a third party –TSB Offshore Services and Proserve prior 2017. New approach requires operators to submit actual aggregate cost of completed decommissioning activities to the agencies to help with the determination of accurate cost of decommissioning liabilities. Cost data were accessible from the agency's websites (www.data.bsee.gov) BSEE, 2017) and (www.data.boem.gov) (BOEM, 2017).
Nigeria	No publicly accessible data on agency's websites and none from extra sources.

Table 20: Production decline and collateral management

Region	Description of current approach and performance
Alberta Canada	On its website, AER publishes "credible information about Alberta's energy resources that can be used for good decision making [ ] and gives stakeholders independent and comprehensive information on the state of resource and supply and demand." ST98 is an annual report showing the trend of remaining reserves by resources (www.aer.ca) (AER, 2017).
UKCS	OGA publishes the production data for each field in its Petroleum Production Reporting System (PPRS), which is accessible from the agency's website (www.ogauthority.co.uk) (OGA, 2017).
OCS	(www.data.bsee.gov) BSEE, 2017) and (www.data.boem.gov) (BOEM, 2017).
Nigeria	There is inconsistent historical production data publicly accessible from NNPC and DPR's websites. No information on production forecast but has aggregate data on remaining reserves.

Table 21: Financial assurance-exposure management

Region	Description of current approach and performance
Alberta, Canada	Using its defined and published standard unit rates of cost and value of assets, AER will demand for a financial assurance from an operator, if the deemed asset value is less than the deemed liabilities. It accepts only cash collateral or letter of credit. While the amount of cash or letter of credit is not published, the LMRs are regularly updated and publicly accessible from AER's website.
UKCS	OCS uses a similar approach to AER, but the operator and the OGA sign a decommissioning deed where the operators contribute fund toward decommissioning, and if they default, the OGA can access the funds to complete decommissioning of the field.
OCS	OCS uses a similar approach to AER, but accepts bonds from financial institutions with minimum of Aa credit rating.
Nigeria	There is no reference to any form of financial assurance for decommissioning in the regulatory agency's websites. *While for onshore fields there may be no decommissioning fund, the revised production sharing agreements for the offshore fields had a requirement for operators to set aside a decommissioning fund for the fields (Azaino, 2012*)

Table 22: Vulnerability to decommissioning default risk and volume of scope of work for decommissioning

Region	Description of current approach and performance
Alberta, Canada	Using the LMR, which is published regularly, AER incentivize operators to incrementally complete decommissioning and remediation of sites to ensure that their LMR does not drop below 1 and they are not required to make more cash or letter of credit deposit with AER.
UKCS	While information on the website and OGA's website indicate that bonds are collected from operators, there is publicly accessible information on a form of vulnerability ratio for the fields
OCS	Similar approach as AER.
Nigeria	There is neither a reference to a vulnerability ratio nor a continuous drive to incrementally abandon some wells/facilities that have been left idle for a long time.

Table 23: Regulations and regulatory capacities

Region	Description of current approach and performance
Alberta, Canada	Regulatory agency for decommissioning and industry growth/operations is Alberta Energy Regulator (AER). It coordinates with the environmental regulatory agency, Alberta Environment and Parks (AEP) for approval of reclamation certificates for decommissioned petroleum facility locations. Decommissioning plans are published and publicly accessible for free, on AER's website. (www.aer.ca) (AER, 2017).
UKCS	Regulatory agency for decommissioning is the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED), which is with the Department of Business, Energy and Industrial Strategy (BEIS). It coordinates with Oil and Gas Authority (OGA), the regulatory agency for industry's operations in the UK. All decommissioning plans submitted by operators (either already approved or undergoing reviews –with the comments), are public accessible for free, via its websites. DECC (www.ogauthority.co.uk) (OGA, 2017).
OCS	Regulatory and licensing agencies – BSEE and BOEM. (www.data.bsee.gov) BSEE, 2017) and (www.data.boem.gov) (BOEM, 2017).
Nigeria	Regulatory and licensing agency is the DPR which coordinates with serval environmental agencies. Effectively, final decision still lies with the government's executive minister for petroleum. There are no decommissioning plans or well abandonment plans, published on DPR's websites.

Table 24: Stakeholder engagement and EIA process

Region	Description of current approach and performance
Alberta Canada	There is an Environmental Site Assessment (ESA) requirement before a decommissioning plan can be approved. Under the ESA, the operator is expected to submit the plan for stakeholders' comments at least 30 days before the agency approves the plan. Stakeholders can issue their disagreement with the plan in a statement of concern which must be resolved before decommissioning plan is approved (www.aer.ca) (AER, 2017). There is information on the AER's website on a voluntary alternative dispute resolution process, for dis-satisfied stakeholders to escalate issues raised over a proposed decommissioning plan but not addressed to the satisfaction of the concerned stakeholder.
UKCS	Public and stakeholders such as fishermen are actively consulted before any decommissioning plan is approved. There is a stakeholder engagement guidance document published by the oil and gas trade association, Oil and Gas UK, to help operators ensure effective stakeholder engagement before and during decommissioning (www.ogauthority.co.uk) (OGA, 2017). Section 7 of the offshore petroleum production and pipelines (assessment of environmental effects) regulations 1991 (as amended) clearly provides for aggrieved stakeholders to seek redress in court.
OCS	Similar to Alberta and UKCS, BSEE ensures effective stakeholder engagement through a public notice and multi-agency permitting and approval process.
Nigeria	Decommissioning process including a stakeholder engagement process is not explicitly described on the websites, but is expected to follow the existing EIA process as required by environmental guidelines and standards for the petroleum industry in Nigeria (EGASPIN). Approvals from other agencies like the federal ministry of environment and several state environmental protection agencies will also be required. The EIA process has not been known to be very effective in Nigeria.

Table 25: Post-decommissioning phase management (provisions for post decommissioning activities and environmental, social, health, and economic objectives at EOFL)

Region	Description of current approach and performance
Alberta, Canada	How post-decommissioning phase issues will be addressed is not explicit from the website. Except that under the Frequently Asked Question (FAQ) there is one reference only, to an operator assuming responsibility into perpetuity for any infrastructure left beneath the surface.
UKCS	For UKCS, the decommissioning requirement holds operators severally and collectively liable into perpetuity for post-decommissioning phase. However, it was not explicit how the post-decommissioning economic and labor challenges would be addressed.
OCS	Post-decommissioning phase activities are handled similar to UKCS
Nigeria	There is no reference to post-decommissioning phase, either from the regulatory agencies websites or outside sources.

Table 26: Fairbanks maturity model results - as-is maturity levels and comparative analysis for Nigeria, Alberta, UKCS, and OCS fields

Maturity Level / **Attribute**	**Level 1**	**Level 2**	**Level 3**	**Level 4**	**Level 5**
Inventory of fields/facilities for decommissioning monitoring	Nigeria				Alberta; UKCS
Cost of decommissioning liabilities	Nigeria				Alberta; UKCS
Production decline and production collateral management		Nigeria		Alberta; UKCS	
Financial assurance-exposure management	Nigeria		UKCS		Alberta
Management of scope, vulnerability to, and coverage for decommissioning liabilities	Nigeria			UKCS	Alberta
Stakeholder engagement and EIA process		Nigeria			Alberta; UKCS
Regulatory landscape	Nigeria				Alberta; UKCS
Post-decommissioning phase management	Nigeria		Alberta	UKCS	

Based on information from websites of regions with significant experience in decommissioning activities for petroleum fields (Tables 18 - 25) and information from NNPC and DPR websites in Nigeria, the level of maturity for sustainable decommissioning framework for onshore fields in Nigeria can be concluded to be at Level 1 ad hoc maturity level as shown in Table 26 and Figure 83.

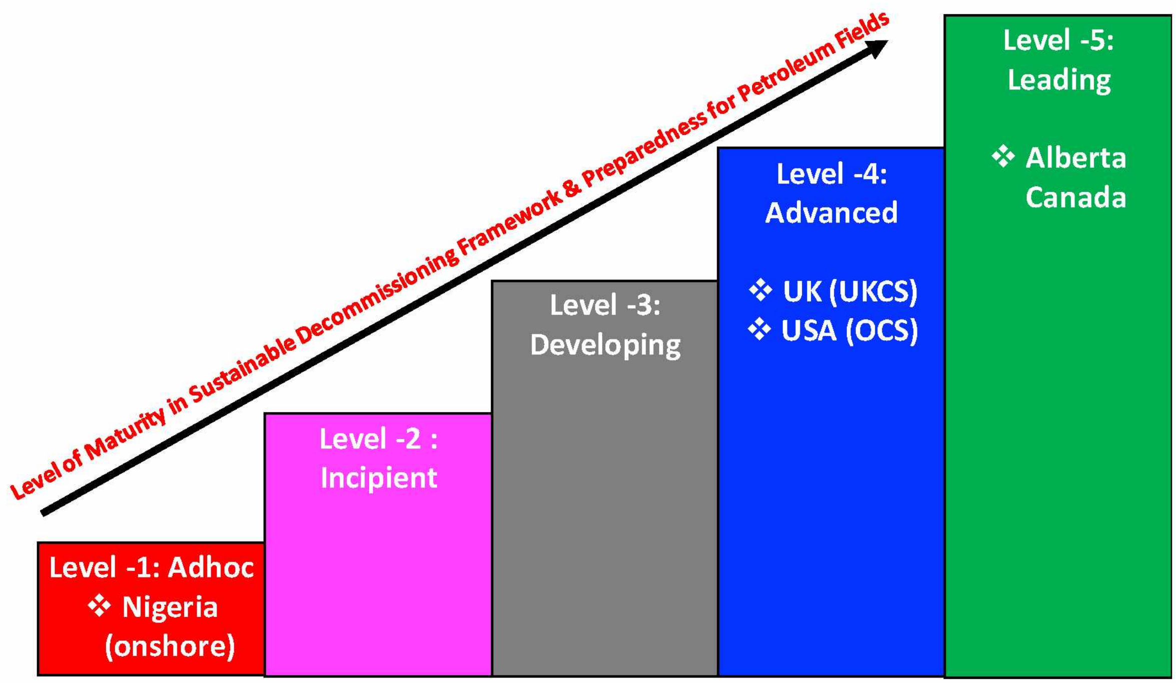


Figure 83: Fairbanks maturity model – Level of maturity for onshore fields in Nigeria

A comparative evaluation between some regions with leading experience on decommissioning of petroleum fields also shows that decommissioning frameworks for Nigerian onshore crude oil fields are steps behind those of Alberta in Canada, UKCS in UK, and OCS in the United States as shown in the spider diagram in Figure 84.

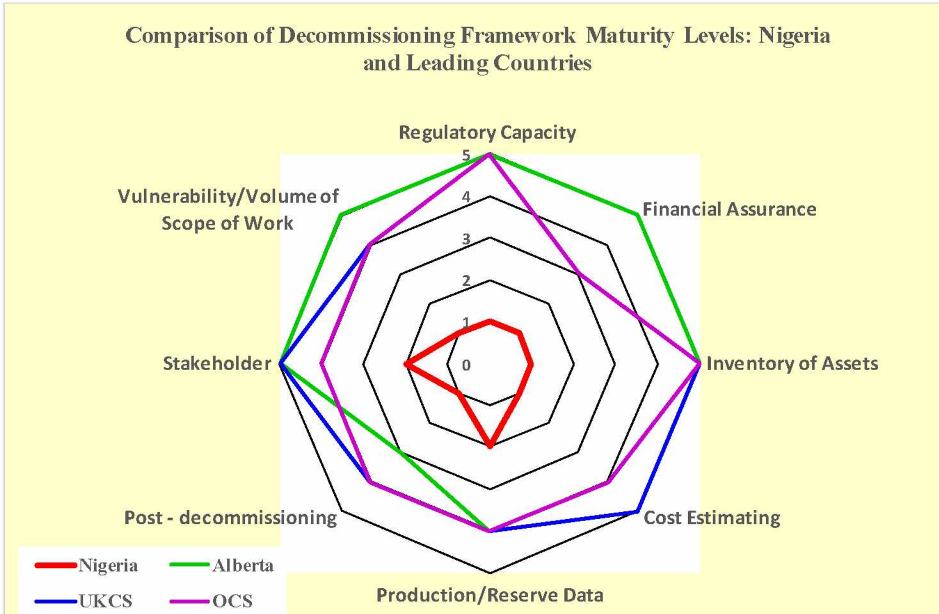


Figure 84: Spider diagram – Level of maturity of sustainable decommissioning framework between Nigeria, UKCS, and Alberta Canada

9.5.1. Discussions of Gaps for Sustainable Decommissioning of Nigerian Onshore Crude Oil Fields

From Fairbanks maturity model, Nigeria is at maturity Level 1 (Figures 83 and 84, and Table 25), in six out of the eight identified important elements that are necessary for a sustainable decommissioning framework, and at maturity Level 2 in the remaining two elements. Overall, Nigeria can be described to be at Level 1 maturity, which is an ad hoc stage, in the development of a sustainable decommissioning framework and readiness for decommissioning of its onshore crude oil fields. This study has shown that in comparison to Alberta Canada and UKCS that are at maturity Level 3/4, there are several gaps in the existing decommissioning frameworks in Nigeria that needs to be closed before the country can achieve sustainable decommissioning of its onshore crude oil fields.

There is no comprehensive and regularly updated database for all the assets and facilities located in onshore and even offshore fields in Nigeria. The existing dataset on the NNPC's website mentioned some fields and facilities, but with inconstancies over the years and no report on details, such as their size and year of installation. Applicable to any country, region, and even corporate bodies, Nigeria needs to set up an accurate and publicly accessible inventory database for all the fields and assets in the onshore region and even the entire nation. Norway is already making this foundational effort toward the development of a plan for decommissioning of its petroleum fields. There is an effort to develop a database for all the petroleum producing assets in Norway (Myrseth et al., 2017). The Netherlands is also working toward getting a database of accurate inventory of its assets and facilities (Energie Beheer Nederland B.V., 2016).

The cost estimate for the fulfillment of all decommissioning liabilities for crude oil fields is a critical element to any successful decommissioning framework. Alberta Canada, UKCS, and OCS through the regulatory agencies have the ROM cost of settling decommissioning liabilities from the fields, even at individual operator's level. This will help to facilitate discussion with the public and stakeholders, and simultaneously support the development of other elements of a sustainable decommissioning framework. For example, knowing the cost of decommissioning liabilities will help with plans for the amount and type of financial assurance to demand from operators. Hitherto, there has not been a ball park cost estimate for the decommissioning liabilities for Nigerian onshore crude oil fields in the public domain. This study has developed a model to use for the determination of a ball park cost estimate for decommissioning liabilities from publicly declared cost of ARO. It has developed, to the best of my knowledge for the first time, the base cost estimate for decommissioning of Nigerian onshore crude oil fields. Where there are challenges with proprietary status of data on decommissioning, natural resource producing regions such as Nigeria can adopt the methodology introduced in this study to determine a good ROM cost estimate for their decommissioning liabilities. This information should be made publicly accessible the stakeholders.

Nigerian regulatory agency and the national oil corporation have not been consistent and comprehensive in the reported historical crude oil production. Countries with leading practice in this element of sustainable decommissioning framework do publicly provide both the historical production data and forecasted future production data (Munisteri & Umekwe, 2017). Nigeria can adopt a simple production decline curve approach to provide future production outlook.

The current decommissioning framework in Nigeria has gaps in all other elements in comparison to attributes in the Fairbanks maturity model for sustainable decommissioning policy frameworks. Based on the identified gaps from the Fairbanks maturity model, Nigeria can develop a roadmap toward maturity of its decommissioning framework to attain a Level 4 maturity status. The steps may include the use of simple methods and programs to close these gaps, such as the simple models and metrics introduced in this study to evaluate, trend, and monitor vulnerability to decommissioning default risk. With the maturity model, the progress toward this policy objective can be regularly monitored, compared, and communicated in a manner that is easily understandable to stakeholders and will incentivize them to be effectively engaged toward the achievement of a sustainable decommissioning of the onshore fields.

10. Summary of Research Findings and Recommendations, and Conclusions

From the research findings and results of the demonstration models, several recommendations to improve on the level of preparedness for decommissioning phase activities can be made for the petroleum industry in general and Nigerian onshore crude oil fields in particular. Several conclusions about sustainable decommissioning in the petroleum industry can also be reached from the research findings and results, which will in turn answer the earlier set research questions and demonstrate that the research objectives have been met.

10.1. Summary of Research Findings and Recommendations

In the petroleum industry and relative to offshore field decommissioning, onshore field decommissioning attracts less attention from industry stakeholders and even academia. A key contributing factor is the fact that it is mostly under national and local jurisdiction, unlike offshore field decommissioning that is under international legal jurisdiction. The national legal frameworks are not deliberately crafted to compel the petroleum industry to internalize its social cost as crude oil production is a key factor in any oil producing economy and nations try to incentivize crude oil production and accruing rent. It is recommended that countries and regions with onshore petroleum fields should review the decommissioning elements in their petroleum policies to ensure that a blanket extension of elements meant for offshore petroleum fields do really also apply to onshore petroleum fields.

Generally, in most industries in the natural resource sector, owing to the socioeconomic importance and social cost of natural resource developments, effective public stakeholder participation is required for the development and implementation of natural resource management strategies and policies, such as sustainable petroleum fields decommissioning policies. Effective stakeholder participation requires adequate information on decommissioning related parameters, such as the cost of decommissioning liabilities, forecast of remaining future production, and vulnerability to and imminence of a default in meeting decommissioning obligations. The proprietary nature of these information creates information asymmetry that is biased in favor of oil company operators and against public stakeholders. This makes it challenging for stakeholders to proactively have appropriate and adequate information to enable them to effectively participate in the development and implementation of a sustainable decommissioning policy for petroleum fields.

From this research, it has been demonstrated that the occurrence of and readiness for decommissioning can be predictively and proactively monitored and evaluated by the public. It is recommended that stakeholders begin to take advantage of the low transaction cost methodologies presented in this study to gather sufficient information on decommissioning to be adequately incentivized to engage in the development and implementation of a sustainable decommissioning strategy for petroleum fields. The information asymmetry with respect to decommissioning of petroleum fields can be reduced by the use of novel methodologies and resultant models as developed and presented in this dissertation that require minimum publicly available input data on decommissioning related activities. At an aggregate level, there is sufficient publicly declared decommissioning related information for public stakeholders to synthesize with minimal effort for an understanding of the cost and vulnerability to decommissioning default risk at least at a high level that is suitable for policy development.

The level of preparedness for the decommissioning phase has been scantly studied in a comprehensive and interdisciplinary manner. While few leading countries/entities have developed different approaches to some elements of a sustainable decommissioning framework, there is no comprehensive and publicly amenable monitoring and evaluative tool for sustainable decommissioning framework. In other industries and for business improvements and even a closely related issue such as abandonment of solid mineral mines, there are maturity models for process evaluation and benchmarking. Wide gaps exist between different nations, regions, and corporate entities on approaches to decommissioning activities in the petroleum industry. It is recommended that regions and even corporate entities should regularly monitor and evaluate their level of preparedness for decommissioning phase activities using a graded maturity scale model, such as the Fairbanks maturity model for sustainable decommissioning of petroleum fields developed and presented in this dissertation. It will help to provide a common basis for predictive and proactive monitoring and evaluation of level of progress and improvement drive toward a sustainable decommissioning goal.

With particular focus on the case study, Nigerian onshore fields are depleting and may die intestate or leave the government, next generation, or whoever will inherit them, bequeathed with assets that may not be of sufficient value to pay for the decommissioning liabilities. At the face value of publicly declared plans, none of the current Nigerian onshore field operators investigated in this study reported a potential EOFL beyond 2050. There is an urgency to plan for how the decommissioning liabilities will be properly managed as the remaining time before the asset's value could fall less than the decommissioning liabilities is not adequate for a sustainable decommissioning plan and policy development in Nigeria. Once the asset value falls below the cost of decommissioning liabilities, the fields will become similar to toxic assets in a bequest and could become a social and public burden.

It is recommended that Nigeria should start the preparation for the decommissioning of its onshore crude oil fields in earnest. The imminence of and vulnerability to decommissioning default risk for the onshore fields is very high. Considering characteristically how long it takes to develop and implement a policy in Nigeria, a lead time in excess of 40 years and convenient remaining revenue in excess of 20 times the cost of decommissioning liabilities, may be required to achieve sustainable decommissioning of these fields. This is a lead time and remaining revenue collateral that may not be available based on the results from this study. From the results, the DCR is less than 20 and the DCRV is less than 20 for the onshore crude oil fields in Nigeria.

The most reliable revenue stream that can be used to address decommissioning liabilities is the tax revenue stream. Royalty and JV profit share revenue streams are fraught with operational efficiency and fiscal stability challenges. The government's plan for decommissioning should be more critical of the behavior of a policy on the tax revenue stream than other revenue streams, such as JV profit share. Within the limits of the assumptions made in this study, the JV profit share does not offer a good assurance and adequate funds for decommissioning liabilities. Therefore, the government should consider this factor when developing incentives for marginal operators who are taking over operatorship of the onshore crude oil fields. It may even be advisable for the government to pull out of JV agreement and optimize on the use of tax fiscal policy element for rent collection rather than continue in JV arrangements. The conventional use of tax break incentives for marginal operators may not be as optimal and leveraging for decommissioning activities and may need a re-consideration.

As large MOCs or other oil companies plan to divest from the crude oil fields in the onshore regions, Nigeria should consider policy elements that will offer the most financial assurance and coverage for the decommissioning liabilities of the fields before the approval of divestment deals. A field's pro forma social cost should be fully captured in the sale price and reflected in the net benefits that go to the operators. Else, the government and non-benefited future generations will pay the excess of the social cost over the private cost for these fields, which is a classic case of external diseconomy.

10.2. Contribution to Knowledge

First, a new methodology and model that determines the cost of decommissioning liabilities from publicly declared, financially audited, and other corporate reports was introduced in this study as an extension to the frontier of knowledge in petroleum and natural resource management.

Second, this study also introduced a new methodology and model to determine decommissioning cost coverage ratio, imminence and vulnerability to the risk that the oil companies will fail to meet their decommissioning liabilities. This methodology and associated model will help in providing a better understanding of risk management, particularly decommissioning risk management in petroleum engineering, natural resource economics, and engineering project management.

Third, as an extension to the frontier of knowledge in decommissioning of petroleum fields, this study also introduced a graded maturity scale model described as the Fairbanks maturity model for sustainable decommissioning of petroleum fields. The graded maturity scale is a popular tool for monitoring and evaluating business and strategy improvement efforts in several industries and disciplines, such as project management, and software and information technology development, and even for closely related issues of abandonment of solid mineral mines in Australia. It has hitherto not been pioneered or developed for decommissioning in the petroleum industry. The Fairbanks maturity model will help provide a common basis for predictive and proactive monitoring and evaluation of level of progress and drive for improvement toward a sustainable decommissioning goal by nations, regions, and entities.

Fourth, a possible cost estimate range of $20 billion to $50 billion for decommissioning liabilities from Nigerian onshore crude oil fields has been introduced into the public space as a kick start for public engagement on decommissioning of these fields. The low level of maturity (Level 1, ad hoc level) in preparedness for activities of the decommissioning phase, the very near imminence of less than a generation away, and high vulnerability to decommissioning default risk from Nigerian onshore crude oil fields were also seminally introduced into the academic space from this study. The baseline comparative analysis results from the Fairbanks Maturity scale model could engender the development of a roadmap toward the closure of gaps in frameworks for sustainable decommissioning of petroleum fields in Nigeria.

To the best of my knowledge, these approaches are novel and their demonstration using Nigerian onshore crude oil fields is seminal, particularly when considering studies on decommissioning of onshore fields in Nigeria. Previous studies, even at a more global level, were focused on only decommissioning of offshore petroleum fields.

10.3. Conclusion

A methodology that overcomes decommissioning information asymmetry in the petroleum industry was developed and successfully demonstrated with Nigerian onshore crude oil fields. This answered the first research question, is there a way to overcome the information asymmetry in the petroleum industry to know the size and cost of decommissioning liabilities arising from the crude oil fields (Table 26). It also satisfied the corollary objective of introducing a model to estimate the cost of decommissioning liabilities from publicly available data for onshore fields in Nigeria.

Table 27: Answers to research questions and fulfillment of research objectives

Research objectives	Research question	Answers to research questions and fulfillment of research objectives
Develop a simple and public-amenable methodology to determine the cost of decommissioning liabilities for a region or entity, using only publicly available and reliable input information	Is there a method to overcome the information asymmetry in the petroleum industry to know the size and cost of decommissioning liabilities arising from the crude oil fields?	A new methodology to determine cost estimates for decommissioning liabilities from publicly declared asset retirement obligation (ARO) data in financial reports was introduced and demonstrated with a model for Nigerian onshore crude oil fields, described as Nigeria_ARO_Cost_Model. It provided a baseline huge P50 cost estimate of $3 billion and a P90 cost estimate of $7.5 billion to meet the decommissioning liabilities of Nigerian onshore crude oil fields.
Seminally demonstrate the looming size of decommissioning liabilities and the vulnerability to decommissioning default risk for crude oil fields in the Nigerian onshore region.	What is the vulnerability or exposure of the government/public to the risks resulting from decommissioning of the onshore fields and the imminence of its occurrence?	Two metrics for vulnerability to and imminence of occurrence of decommissioning default risk, decommissioning coverage ratio (DCR), and decommissioning coverage ratio vector (DCRV) were introduced. When combined, they provide an indication of vulnerability to and imminence of decommissioning default risk. A model DCR_DCRV_Nigeria_Onshore was developed to demonstrate the methodology, which revealed high vulnerability to and imminence of decommissioning default risk for Nigerian onshore crude oil fields.
Develop a simple and public-amenable methodology to evaluate and determine vulnerability to and imminence of decommissioning default risk.		
Develop a simple and public-amenable methodology to systematically monitor, evaluate, and benchmark level of preparedness or maturity of policy frameworks for sustainable decommissioning of petroleum fields. Improvement toward sustainable	Is there a method to benchmark the level of preparedness for decommissioning phase of crude oil field amongst nations or entities so as to systematically and incrementally drive improvement toward sustainable decommissioning	A new sustainable decommissioning maturity model, Fairbanks Maturity Model was developed and demonstrated with Nigerian onshore crude oil fields, which shows that sustainable decommissioning policy development in Nigeria is at the lowest level of maturity – Level 1 or ad hoc level.

A methodology and metrics to determine the vulnerability of a region or entity to decommissioning default risk was also developed and demonstrated with Nigerian onshore crude oil fields. The metrics encompass the size and temporal outlay of the collateral provided for decommissioning liabilities by the natural resource. They were appropriately described for a region as CDR and DCRV. Combined, they reflect the imminence of and vulnerability to decommissioning default risk based on the remaining value of a revenue stream of interest. Using this methodology and metrics, the second research question, what is the vulnerability or exposure of the government/public to the risks resulting from decommissioning of the onshore fields and the imminence of its occurrence, was answered. The corollary objective to ascertain if there will be sufficient resources to pay for the proper decommissioning of the onshore crude oil field in Nigeria when it occurs, and a determination of its imminence of occurrence, was also achieved. Without a deliberate effort to quickly establish and implement a sustainable decommissioning framework as espoused in this study, Nigeria may not have sufficient resources to pay for the sustainable decommissioning of its crude oil fields, when their EOFL occur. The EOFL may begin to occur within the next few decades, which given the antecedents of policy development and implementation in Nigeria, is not a luxury of time for the development and implementation of a sustainable decommissioning policy framework.

A graded maturity scale model, described as the Fairbanks maturity model for sustainable decommissioning of petroleum fields, was developed and demonstrated in a comparative analysis between Nigeria and some regions with leading practices in the decommissioning of petroleum fields. The common basis for predictive and proactive monitoring and evaluation of level of progress and improvement drive toward sustainable decommissioning of petroleum fields provides an answer to the third research question, on the availability of a monitoring, evaluating, and benchmarking tool for frameworks to support sustainable decommissioning of petroleum fields.

Overall, the research objectives were also met (Table 26). A simple and public-amenable methodology to determine the cost of decommissioning liabilities for a region or entity, using only publicly available and reliable input information was developed, presented, and demonstrated. A simple and public-amenable methodology to evaluate and determine vulnerability to and imminence of decommissioning default risk was also developed, presented, and demonstrated. The study also seminally demonstrated the looming size of decommissioning liabilities and the vulnerability to and imminence of decommissioning default risk for the onshore fields in Nigeria. By so doing, information has been provided without barriers to stakeholders to support their much-needed effective participation and engagement for a sustainable decommissioning policy development process. Furthermore, there is some extension to the frontier of knowledge in project and engineering management, cost estimation, production forecast, and economic evaluation in petroleum engineering, environmental and natural resource policy, and economics.

For the case study of Nigerian onshore crude oil fields, if for any catastrophic reasons, they are suddenly abandoned by MOCs and current investors at any moment form now, it will be analogous to dying intestate in a sudden death scenario. The bequest of the remaining revenue accruable for the fields may not be adequate to pay for the decommissioning liabilities. This is more worrisome, given that the Nigerian government is not known for efficient management of operations of any business venture in Nigeria. Moreover, the cost, resources, time, and effort of decommissioning liabilities for proper completion of decommissioning projects will be significantly higher, if the government were to execute the decommissioning projects.

Even with an anticipated end of economic life and some proactive preparedness for decommissioning as typified by the euthanasia death scenario, the situation could still be analogous to dying with a will, but on a toxic bequest. The remaining revenue from available revenue streams accruable to the government and the coverage they provide for decommissioning liabilities may not be comfortable even at this time, talk less of the future when more resources would have been exploited. The remaining revenue or value of assets could easily get toxic as the decommissioning liabilities could be large enough to wipe out the remaining revenue from the fields, therefore discouraging investors from buying into the assets. Therefore, the government could be left to execute the decommissioning projects albeit inefficiently and at a higher cost or fail to execute them properly and the public left to suffer the environmental, economic, and societal degradation from the remains of the petroleum industry in the onshore field regions of Nigeria.

In either of the scenarios, it does not portend good for Nigeria to currently be without a comprehensive, proactive, and publicly visible sustainable decommissioning policy and strategy for its onshore fields, and also the offshore fields. Information asymmetry that favors the oil companies is not a sufficient reason for the public stakeholders and regulatory agencies to be slow in driving the goal of sustainable decommissioning of the fields, particularly leveraging the presented outcome of this research. If the status quo is maintained, these fields may die intestate or with a will bequeathing a toxic estate to future generations.

10.4. Limitations and Suggestions for Further Studies

The data set used for the cost estimation model is relatively small. The results should be used recognizing these limitations. It is suggested that a continuing survey of financial reports published by oil companies in Nigeria should be made for a longer period of time, so as to get a wider array of data to support a more robust and reliable result from the cost estimation model. Crude oil production data from Nigerian onshore regions were inferred over some period due to non-availability of data. Published crude oil production data for Nigeria are collectively onshore and offshore production data. Government agencies should leverage their relationship with the national petroleum regulatory agencies to obtain more reliable data to update these results for policy making decisions.

Data gathered for the Fairbanks maturity model assessment were from only web-based sources. While this satisfies the stakeholder participation bias of this study, a self-assessment by the regulatory agencies may provide the government a better picture of the gaps that need to be closed. This self-assessment should also be comparatively done amongst several nations instead of only three, as done in this research.

Furthermore, this study is exploratory and the results presented are at a high level. Further research work should use a larger dataset to validate the results and methodologies.

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Appendix A: Some Nigeria Onshore Operators and Publicly Reported ARO Data (i)

	Company	Financial Report	OMLs	Reported Cost Year	Report Pages	Reported EOFL	Reported Inflation	Reported Discount Rate %	Reported ARO $MM	Facilities	Date Retrieved	Notes	
1	Heritage PLC	2012	30	2012	28-34	2035	Assumed 2%	10%	22.748	9	27_Dec_2016	Afiesere (60MBPD), Eriemu (60MBPD), Evwreni (30MBPD), Kokori (90MBPD), Oweh (30MBPD), Oroni (30MBPD), Osioka(15MBPD), Olomoro/Oleh (60MBPD)	www.sedar.com
	Heritage PLC	2013	30	2013	61	2035	Assumed 2%	10%	20.998	9	27_Dec_2016	Afiesere (60MBPD), Eriemu (60MBPD), Evwreni (30MBPD), Kokori (90MBPD), Oweh (30MBPD), Oroni (30MBPD), Osioka(15MBPD), Olomoro/Oleh (60MBPD)	
2	Eland	2012	40/49	2012	43	2019	Assumed 2%	5%	17.735	9	27_Dec_2016	Opuama (30MBPD)	www.elandoilandgas.com
	Eland	2013	40/49	2013	18,37, 53-54	2026	Assumed 2%	2.75%	11.978	9	27_Dec_2016	Opuama (30MBPD)	
	Eland	2014	40/49	2014	60-64	2026	4.45% (from 2015 report page 70	2.75%	12.305	9	27_Dec_2016	Opuama (30MBPD)	
	Eland	2015	40/49	2015	70	2026	2% (from 2015 report page 70	2.75%	9.809	9	27_Dec_2016	Opuama (30MBPD); A study done by RPS energy consultants for Eland in 2013 led to change of EOFL from 2019 to 2026 and reduction in ARO from $17.735MM to $11.978MM	
3	Seplat	2015	4/38/41	2011	Pp 183 of 2015 report	2025	Assumed 2%	NA	10.112	3	27_Dec_2016	Oben (30MBPD), Sapele (60MBPD),Amukpe (30MBPD)	www.seplatpetroleum.com
	Seplat	2015	4/38/41	2012	Pp 183 of 2015 report	2025	Assumed 2%	15%	15.727	3	27_Dec_2016	Oben (30MBPD), Sapele (60MBPD),Amukpe (30MBPD)	
	Seplat	2015	4/38/41	2013	Pp 183 of 2015 report	2027	Assumed 2%	12.40%	14.578	3	27_Dec_2016	Oben (30MBPD), Sapele (60MBPD),Amukpe (30MBPD)	
	Seplat	2015	4/38/41	2014	Pp 183 of 2015 report	2036	Assumed 2%	14.64%	9.838	3	27_Dec_2016	Oben (30MBPD), Sapele (60MBPD),Amukpe (30MBPD)	
	Seplat	2015	4/38/41	2015	Pp 183 of 2015 report	2052	Assumed 2%	11.10%	2.971	3	27_Dec_2016	Oben (30MBPD), Sapele (60MBPD),Amukpe (30MBPD)	
	Seplat	2015	4/38/41	2027	Pp 183 of 2015 report	2027	Assumed 2%	12.40%	71	3	27_Dec_2016	Oben (30MBPD), Sapele (60MBPD),Amukpe (30MBPD)	

Appendix B: Some Nigeria Onshore Operators and Publicly Reported ARO Data (ii)

	Company	Financial Report	OMLs	Reported Cost Year	Report Pages	Reported EOFL	Reported Inflation	Reported Discount Rate %	Reported ARO $MM	Facilities	Date Retrieved	Notes
Data below were not selected for the calculation. Some of the line items either did not have EOFL, discount rate or local currency/US $ exchange rate used in the financial reports declared . In subsequent years, some of the companies acquired more assets in different locations and were no longer Nigeria onshore pure plays.												
	Seplat	2015	4/38/41	1/1/2011 (Effectively 2010)	Pp 183 of 2015 report	2052		NA	8.8	3	27_Dec_2016	Oben (30MBPD), Sapele (60MBPD),Amukpe (30MBPD)
4	Shoreline Resources		30		108-115			NA		9	27_Dec_2016	Afiesere (60MBPD), Eriemu (60MBPD), Evwreni (30MBPD), Kokori (90MBPD), Oweh (30MBPD), Oroni (30MBPD), Osioka(15MBPD), Olomoro/Oleh (60MBPD)
5	NDEP	2012	Ogbele	2011		NA	NA	NA	14.7	3	27_Dec_2016	Ogbele field circa 10 MBPD and Diesel refinery and wells
	NDEP	2013	Ogbele	2012	PP 46 of 2013 report	NA	NA	NA	NGN 1273	3	27_Dec_2016	Ogbele field circa 10 MBPD and Diesel refinery and wells; just acquired OML 34; just acquired OML 34 as at the time of this report.
	NDEP	2014	34	2013	pp 34/ 68 of 2014 group report	Assumed 2023 (10 years)	10%	10.32%	NGN 1403	3	02_Feb_2017	Utorogu(30MBPD), Ughelli West(30MBPD), Ughelli East (30MBPD); cost reported in Nigeria Naira
	NDEP	2015	34	2014	pp 102 of 2015 report	2024(10 years)	10%	10.32%	8.39	3	02_Feb_2017	Utorogu(30MBPD), Ughelli West(30MBPD), Ughelli East (30MBPD); cost reported in Nigeria Naira
	NDEP	2015	34	2015	pp 102 of 2015 report	2035	10%	10.32%	2.8	3	02_Feb_2017	Utorogu(30MBPD), Ughelli West(30MBPD), Ughelli East (30MBPD); cost reported in Nigeria Naira ;EOFL revised from 10 years asset life to end date 2035
6	First Hydrocarbon Nigeria (FHN)			Limited information								
7	First Exploration & Production Company Limited	NA-privately held	34	NA	NA	NA	NA	NA	NA	NA		OMLs 71 & 72 -(6.75% WI), and OMLs 83 & 85 -(40% WI) are shallow offshore locations
8	Sepatro	Not a pure play onshore fields operator										
9	Seven Energy		4,38,41; 13 & 14	NA	NA	2027 & 2039		Not pure crude oil play				
10	Amni International	Not a pure play onshore fields operator										
11	ND Western		34	NA								
12	Neconde		42	NA	NA	NA	NA	NA	NA	7		
13	OANDO	Not a pure play onshore fields operator and also operates outside Nigeria										

Appendix C: Sample Screenshot from MS Excel Based Nigeria_DCRV_Model

Read Me

This model provides a simple way to estimate the decommissioning coverage ratio (DCR) and Decommissioning coverage ratio vector (DCRV) for a crude oil asset or group of assets. There are 13 worksheets in this file including this introduction worksheet. The red color tabs are input worksheets, the green color tab worksheets are the results and the grey tabs are some additional chart results.

On worksheets "Remaining_Royalty_2070" and 'Summary_Results_DCR_and-_CRV", the DCRV are manully imputed and color coded after reading them from the "back cumulative tableau for PV remaining revenue or the DCRV tables at the bottom of the spreadsheet "Remaining_Royalty_2070".
Apart from these two worksheets, user may not need to make any other data input beyond those made in the red color tab worksheets.

Euthanasia Deterministic Royalty scenario with terminal date of 50 years from 2020 (a landmark development milestone target year for Nigeria) for convenient planning purposes. Assumed we are at about half way economic life of fields of approximately 100 years from 1957/58. Under this scenario, the Operators do not see the fields continuing to be economically viable after about 2070. About 100 facilities will be producing at best, approximately less than 1000bopd each at a Hyperbolic decline profile and pessimistically, 100bopd at Exponential decline profile. It is assumed that technology and other sociopolitical factors will make them economically unattractive at about 2070. The scenario assumes government will make plans today for decommissioning with this future scenario in mind.

Royalties case: This study examines four main streams of rent from crude oil production in Nigeria -royalties, Joint Venture (JV) profit share, operating revenne, and taxes. For this case, the royalty is the excise or extractio rent collected on every unit of crdue oil extracted from the reservoir. This stream of income is indepdent of the operating operating expenses. This case is evaluting the capacity of the royalty stream of income to be adeqaute for decommissioning liabilities How much risk coverage for decommissioning liabilities does the remaining royalty provide the government and tax payers?

Royalty Revenue (RR) = Production x Royalty rate(Rr)

$RR_n = PV_{10}[Prod_n \times Rr \times Pj \times 365]$, where "PV10" is present value at discount rate of 10%; Rr is the royalty rate which is 20% for onshore Nigeria fields; "Pj" is deterministic price for crude oil where "j" is either high, mean or low crdue oil price case; "Prodn" is the annual crude oil production rate in BOPD for year "n" from 2016, 2017, 2018 2070

Crude oil production data for Nigeria and assumptions made to create synthetic production rates for the onshore fields in Nigeria.
There are no public accessible crude oil production data specific for onshore fields in Nigeria. This study assumed all reported production figures for Nigeria by BP Petroleum Statistics to be from Onshore fields between 1957 (inception) to 1978. A reasonable assumption based on when significant oil production commenced from offshore fields. Between 1979 and 1999 the onshore fields crude oil production contribution was assumed to be 70%. Between 2000 and 2009, actual production data sourced from www.datamonitor.com were used. From 2010 to 2015, onshore production a assumed to be about 50% of Nigeria's total crude oil production.